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CONTROLLED CHEMICAL WATERFLOODING
OF VISCOUS CRUDE OIL

by



John David Scott

A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES
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The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies for acceptance, a thesis entitled "CONTROLLED CHEMICAL WATERFLOODING OF VISCOUS CRUDE OIL" submitted by John David Scott in partial fulfilment of the requirements for the degree of Master of Science in Petroleum Engineering.

ABSTRACT

A laboratory study was conducted to determine the recovery of high viscosity crude oil from natural unconsolidated sand by water flooding with a number of chemical solutions. Displacement tests were run using chemical solutions to displace a high viscosity crude oil from artificial packs of unconsolidated core sand. Results of the displacement tests showed that oil recovery was increased by a number of chemical solutions.

Sodium hydroxide in brine at concentrations less than 0.01 per cent by weight had little effect on recovery as compared to brine floods. Sodium hydroxide concentrations of 0.1 per cent or greater increased recovery significantly.

The interfacial tension between Lloydminster crude oil and various aqueous solutions was greatly reduced by the addition of a number of chemicals to the aqueous solutions. The presence of sodium chloride in the aqueous solution reduced the amount of chemical required for the reduction of the interfacial tension between crude oil and the solution to a given level. The reduction in interfacial tension influenced the recovery of oil.

The production of a very stable emulsion and evidence of reduced water mobility during displacement tests suggested that emulsification may have occurred within the core. The formation of an emulsion may have increased oil recovery.

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INTRODUCTION

The purpose of this study was to determine if the recovery of high viscosity crude oil from natural unconsolidated sand by water flooding could be increased by the addition of chemicals to the displacing phase. This study constitutes part of a large research project (1) concerned with the recovery of high viscosity crude oil.

Because the API gravities of high viscosity crude oils are characteristically low, these oils are often referred to as heavy crude oils. While significant reserves of heavy crude oil are found in Western Canada, primary recovery of heavy crude oil reservoirs has been low. Westfall (2) indicated that primary recovery in the Lloydminster heavy crude area was expected to be five or six per cent and secondary recovery by conventional water flood was expected to be 10 to 12 per cent of the initial oil-in-place. In Western Canada more than 95 per cent of secondary recovery projects are water floods and economics will probably dictate the use of water as a flooding medium in most future projects (3). Therefore, there are strong incentives for developing more efficient water flooding techniques for the heavy crude oil reservoirs.

Three previous studies related to this research project have been completed. Collins (4) investigated the influence of viscosity ratio on recovery efficiency in long, unconsolidated sand packs using a native brine as the displacing phase. Scott (5) investigated the influence of sodium hydroxide solutions on the water flood recovery of high viscosity crude oil from an unconsolidated natural sand pack. He

found that sodium hydroxide increased oil recovery and a change toward preferential water-wetting of the sand was evident after it was contacted with weak sodium hydroxide solutions. The reduction in interfacial tension between brine and Lloydminster crude oil upon the addition of alkali to the brine influenced the wettability of the system and the oil recovery. Fazil (6) evaluated the effect of carbon dioxide as an additive to the displacing phase in a series of brine flood tests on a long unconsolidated sand pack. Carbonated brine flooding produced significant increases in oil recovery over conventional water flood. The increase in recovery was attributed to decreases in crude oil viscosity and interfacial tension. The sand pack changed from slightly oil-wet to neutral to preferentially water-wet with successive carbonated brine floods.

Low oil recovery by water flooding of heavy crude oil reservoirs results from low sweep and displacement efficiencies. Sweep efficiency is primarily affected by reservoir heterogeneities and mobility ratio, while displacement efficiency is affected by the capillary forces between fluids and rock surfaces (7). To increase oil recovery by water flooding, sweep and displacement efficiencies should be improved. Displacement efficiency may be increased by altering the capillary forces within the reservoir. A review of literature indicated that a number of relatively simple chemicals exhibited the ability to reduce interfacial tension between crude oils and water and to alter the wettability characteristics of sand. A number of imbibition and interfacial tension tests were conducted to evaluate some of these chemicals. Displacement tests using chemicals in the displacing phase were performed to evaluate the

ability of the chemicals to increase oil recovery. Natural sands, crude oil and reservoir waters from the Lloydminster areas were used during this study.

LITERATURE REVIEW

A literature review of subjects relating to the recovery of oil by water flooding was conducted. Investigations have shown that rock wettability greatly influences the displacement of oil by water from oil reservoirs.

Wettability has been defined by Jennings (8) as the degree to which a solid is wetted by a liquid. The advancing contact angle was defined as the static angle formed by a liquid-fluid interface that has advanced over a solid surface measured through the advancing phase. A solid is considered to be preferentially water-wet if the advancing contact angle is smaller than 90 degrees when measured through the water. Conversely, a solid is preferentially oil-wet if the advancing contact angle measured through the water is greater than 90 degrees.

A number of investigators have shown that the wettability of reservoir rock may depend upon both the crude oil composition and rock type. Benner and Bartell (9) found that normally hydrophilic rock material in petroleum reservoirs may be altered to hydrophobic by adsorption of basic or acidic polar impurities from crude oil. Chemisorption of basic polar compounds appeared to take place at acidic silica surfaces. The ability of some oils to preferentially wet silica sand surfaces has been noted by other authors (10, 11, 12, 13, 14). Some of the petroleum constituents were found to be strongly held at the silica surfaces (15).

A number of authors (16, 17, 18, 19) have demonstrated that the wettability characteristics of core material can be significantly changed during handling and storage. The authors emphasize that special

core handling techniques are required to preserve the original reservoir wettability of cores to be used in later laboratory tests.

Jennings (20, 21) found that strongly held organic material on sand surfaces which caused preferential oil-wettability could not be removed by normal core extraction methods. Mungan (22) found that original wettability of cores could be restored by permitting core surfaces to come into equilibrium with the crude at reservoir temperature.

The preferential wettability of the solid surface in porous media influences the relative permeability, capillary pressure and water floodability characteristics of oil bearing reservoir rock (23, 24). Several investigators (25, 26, 27, 28) have reported that higher water flood recoveries were obtained in preferentially water-wet systems than in corresponding preferential oil-wet systems. Changes in oil and water relative permeability curves can result from wettability changes (29, 30, 31). As a porous medium changes from preferentially oil-wet to preferentially water-wet, at a given displacing fluid saturation, the relative permeability to oil increases and to water decreases.

Imbibition has been defined by Graham and Richardson (32) as the spontaneous taking up of a liquid by a porous solid. They illustrated that imbibition rates were functions of interfacial tension, contact angle, fluid viscosities and characteristics of the rock. Methods for determining wettability of porous media by imbibition tests have been proposed (33, 34, 35).

The effect of interfacial tension on oil recovery has been examined. Some investigators (36, 37) have found that oil recovery by water flooding was increased if the interfacial tension were increased

in water-wet systems and decreased in oil-wet systems. Mungan (38, 39) observed that oil recovery by water flooding could be increased in both oil-wet and water-wet systems by reducing interfacial tension, however the effect was not as pronounced in water-wet systems. Warren and Calhoun (40) noted that breakthrough and ultimate recovery increased as interfacial tension decreased in oil-wet cores. Wagner and Leach (41) found that water flooding at very low interfacial tensions resulted in large increases in oil recovery. Their tests were conducted with pressure gradients well below those calculated to be achievable in a reservoir.

The use of chemicals or "flooding agents" to increase the oil recovery from oil bearing sands has been considered by many investigators. In 1932, Bartell and Miller (42) reported that neither surface tension values of the liquids nor the interfacial tension values of the liquid-liquid system were the dominant factors in the displacement of oil. Effective displacing agents appeared to be those that altered the aqueous solution silica interface either through a high degree of adsorption or through chemical reaction at the interface. Alkaline solutions made with sodium hydroxide or sodium carbonate were found to be effective in displacing oil from silica surfaces. Nutting (43) suggested that an attraction between silica particles (SiO_2) and hydrogen ions of water formed a layer of siloxyl (SiOOH) radicals on the sand surface. These acidic radicals would react with the basic constituents of crude oil so that over the surface there would be a stable chemical combination of the oil with silica. By adding alkaline salts to injected water, the strong base would displace the weaker one from the acidic siloxyl radical,

and the oil, being weakly basic, would be removed. Beckstrom and van Tuyl (44) tested a number of chemicals and found that dilute alkaline solutions of salts of weak acids and strong bases, particularly sodium carbonate, were most effective in displacing oil from oil sands. A one per cent solution appeared to be the best concentration and the effectiveness of the solution rapidly diminished at decreased concentrations.

Dunning, et al, (45) report on wettability reversal using detergents. They distinguish between displacement of oil from an oil-wet surface by wettability reversal and ejection of discontinuous oil drops from porous media having water-wet surfaces after wettability reversal. After reversal of wettability, the formation of small oil drops from larger ones or the deformation of a drop from a spherical shape as it moves through irregular openings of the porous media requires an increase in the area of the oil-water interface which is resisted by the oil-water interfacial tension. Therefore, a low value of interfacial tension should favor the movement of discontinuous oil drops through the irregular openings of the porous media.

Other investigators (46, 47, 48, 49, 50, 51, 52, 53) have shown that wettability adjustment will result in increased oil recovery. In fact, improved oil recovery due to wettability reversal was observed in a field test reported by Leach, et al, (54).

Many chemicals have been tested to determine their ability to alter wettability or reduce interfacial tension. The use of sodium hydroxide has been reported extensively in literature (55, 56, 57, 58, 59, 60, 61, 62, 63, 64). Sodium carbonate was one of the earliest chemicals used (65, 66). Sodium tripolyphosphate ($\text{Na}_5\text{P}_3\text{O}_{10}$) was found to have

surface active properties (67, 68) and several related polyphosphates were also thought to be effective (69). In addition to promising surface active properties, sodium metaphosphate $[(\text{NaPO}_3)_6]$ and sodium (tetra) ethylenediamine tetraacetate (Na_4 EDTA) have the ability to form soluble complexes with many multi-valent ions (70).

Interfacial films have been observed between some crude oils and water (71, 72, 73, 74, 75). These films are believed to result from the adsorption of high molecular weight polar compounds at the interface (76). When a drop of crude oil is aged in brine and retracted so that the interfacial film is compressed, different types of film mobility have been observed (77, 78, 79). Solid or rigid films, which form relatively insoluble skins as the crude oil is retracted, have relatively high interfacial viscosity. Highly mobile or liquid films, which rapidly redistribute and return the drop to a symmetrical form as the crude oil is retracted, have relatively low interfacial viscosity. The presence of rigid films in porous media can adversely affect oil recovery during displacement of oil by water (80). However, rigid interfacial films can be converted to mobile films by adding alkaline chemicals to the aqueous phase thus increasing the pH of the solution (81, 82).

Previous investigators (83, 84, 85), in this research project, have noted the production of stable emulsions during displacement tests of Lloydminster crude oil. The produced emulsions proved difficult to de-emulsify. Strassner (86) found that emulsions of crude oil and water were stabilized primarily by interfacial films that form around droplets of the dispersed phase. He also found that crude oils with viscosities

greater than six centipoises generally formed very stable emulsions. Oil viscosity contributes to the stability of emulsions because it increases the flocculation time of the dispersed water droplets in the emulsion and because larger fractions of polar asphalts and resins are present in higher viscosity, higher density crude oils. Very stable emulsions can form if the pH of the aqueous phase is high and the interfacial tension between the phases is low (87, 88).

A new process for recovering oil by flooding utilizes the unique properties of micellar solutions or microemulsions (89, 90, 91, 92, 93, 94). By controlling the viscosity of the injected fluid as a microemulsion, the mobility of the injected slug can be controlled to completely displace oil. The viscosity of an emulsion is generally greater than the viscosity of the external phase in the emulsion. Therefore, the viscosity of an injection fluid consisting of a small amount of oil emulsified in an external water phase is greater than the viscosity of water. The emulsified fluid is a more efficient displacing fluid than water.

The presence of an electrolyte, such as sodium chloride, in the aqueous phase, can greatly influence interfacial properties (95, 96, 97, 98) between oil and the aqueous phase. At a given concentration of sodium hydroxide, the addition of sodium chloride to the aqueous phase lowered the interfacial tension (99). Burcik (100) mentioned that surface active compounds in solution, such as sodium hydroxide, are charged. As they diffuse into an interface, an electrical charge is built up which tends to repel incoming ions. The addition of electrolyte reduces the potential at the interface and permits more unhindered diffusion at the

interface, thus lowering interfacial tension. Kimbler, et al, (101) suggested that sodium chloride produced a significant change in interfacial film properties because of changes in the electrical properties at the interface.

THEORY

Surface Forces

All molecules are attracted to one another in proportion to the product of their masses and inversely proportional to the square of the distance between them. A water molecule remote from an oil-water interface is surrounded by other water molecules, thus the net attractive force on the molecule is zero. However, a molecule at the interface has a force acting upon it from the oil lying immediately above the interface and water molecules lying below the interface. The resulting forces are unbalanced resulting in an interfacial tension. The unbalanced attractive force creates a membrane like surface. The work required to move a water molecule from within the water phase through the interface is called the free surface energy of the liquid (102). Free surface energy may be defined as the work necessary to create a unit area of new surface and is measured in ergs per square centimeter. The interfacial tension is the force per unit length required to create a new surface and is measured in dynes per centimeter. Therefore surface energy and interfacial tension are identical.

Three interfaces are possible in porous media containing crude oil and water. They are:

1. The porous medium-crude oil interface
2. The porous medium-water interface
3. The crude oil-water interface.

Attractive forces or interfacial tensions exist at each of these interfaces. These are the attractive forces between the porous

media surface and crude oil, between the porous media surface and water, and between the crude oil and water.

It is possible to easily and accurately measure the interfacial tension between two immiscible liquids such as crude oil and water, however, it is not possible to measure the interfacial tension between a solid and a liquid (103). Therefore, information about solid interfacial tensions is derived through the evaluation of the tension differences that exist between a solid-crude oil interface and a corresponding solid-water interface. If two immiscible fluids, such as oil and water, are brought in contact with each other on the surface of a solid, one fluid may completely displace the other from the solid or the system may come to equilibrium with the two fluids forming an angle of contact with the solid. The magnitude of the angle formed will depend upon the relative magnitudes of the three tensions involved. The equilibrium of forces at the water-oil-solid interface is defined in Equation 1.

$$At = \gamma_{so} - \gamma_{sw} = \gamma_{wo} \cos \theta \quad (1)$$

where At = adhesion tension (ergs/cm^2)

γ_{so} = interfacial tension between the solid and oil (dynes/cm)

γ_{sw} = interfacial tension between the solid and water (dynes/cm)

γ_{wo} = interfacial tension between oil and water (dynes/cm)

θ = contact angle measured, by convention, through the denser phase.

The adhesion tension, At , indicates which fluid preferentially wets the solid. A positive adhesion tension indicates that the denser phase,

in this example water, preferentially wets the solid surface. A negative adhesion tension would indicate that oil preferentially wets the solid surface. An adhesion tension of zero indicates both liquids are equally attracted to the surface and the surface is not preferentially wetted by either liquid. If the adhesion tension value is large or the contact angle is small, water will readily spread and thus displace oil from the surface. If the contact angle is large, an outside source of energy is required to displace the oil.

The wettability of the solid surface can be altered by introducing different liquids that change the contact angle. To promote the removal of oil from the surface, the adhesion tension should be minimized. This can be accomplished by reducing the contact angle to zero or increasing the oil-water interfacial tension if the contact angle is less than 90 degrees. However, if the surface is oil-wet and the contact angle cannot be reduced to less than 90 degrees, a reduction in the oil-water interfacial tension should reduce the energy required to displace the oil.

By adding chemicals to injected water that alter the wettability characteristics at sand surfaces, oil recovery by water flood may be enhanced.

Capillary Pressure

A general expression for capillary pressure as a function of interfacial tension and curvature is given by the following equation:

$$P_c = \sigma_{wo} \left(\frac{1}{R_1} + \frac{1}{R_2} \right) \quad (2)$$

where R_1 and R_2 = the principal radii of curvature of the interface

σ_{wo} = interfacial tension between oil and water (dynes/cm)

The capillary pressure in terms of surface forces across an oil-water interface in a capillary tube is defined by the following equation:

$$P_c = \frac{2 \sigma_{wo} \cos \theta}{r} = P_o - P_w \quad (3)$$

where P_c = capillary pressure (dynes/cm²)

P_o = pressure in the oil phase adjacent to the interface
(dynes/cm²)

P_w = pressure in the water phase adjacent to the interface
(dynes/cm²)

σ_{wo} = interfacial tension between oil and water (dynes/cm)

θ = contact angle measured through the water phase

r = radius of the capillary (cm)

From Equation 2 it is apparent that capillary pressure varies directly with interfacial tension. Therefore, capillary forces can be reduced or eliminated by chemicals that will reduce the interfacial tension between crude oil and water.

On a microscopic scale, the entry of water into an oil filled pore in a water-wet porous medium is assisted by capillary pressure. Therefore, for efficient displacement of oil, the interfacial tension should be high. The entry of water into an oil filled pore in an oil-wet porous medium is resisted by capillary pressure. Therefore, for efficient displacement of oil, the interfacial tension should be low to

minimize the energy required to displace the oil.

Water Flooding

The fractional flow equation (104) describing horizontal, linear flow of oil and water in porous media is:

$$f_w = \frac{1 + \frac{K k_o}{q_t \mu_o} \left(\frac{\partial P_c}{\partial X} \right)}{1 + \frac{k_o \mu_w}{k_w \mu_o}} \quad (4)$$

where f_w = fraction of water in the flowing stream at any point

K = absolute permeability of the porous medium (cm^2)

k_o = relative permability to oil

k_w = relative permeability to water

q_t = total fluid flow rate per unit cross sectional area (cm/sec)

μ_o = viscosity of oil ($\text{dyne-sec}/\text{cm}$)

μ_w = viscosity of water ($\text{dyne-sec}/\text{cm}$)

$P_c = P_o - P_w$ = capillary pressure (dynes/cm^2)

X = distance along horizontal axis of the system (cm)

The development of this equation assumes that Darcy's Law applies to multiphase flow, that relative permeability is a function of saturation alone, and that the pressure differential between the two fluids is the capillary pressure.

The effect of capillary pressure on the fraction of water flowing can be evaluated by examining the numerator of Equation 4. The term $\frac{\partial P_c}{\partial X}$ is always non-negative thus a capillary pressure gradient

will always increase the fraction of water flowing. However, for high flow rates and high oil viscosities, the effect of capillary pressure on fractional flow is minimized. If the capillary pressure behind the flood front can be reduced to zero by the addition of chemicals to the displacing phase, then the term $\frac{\partial P_c}{\partial X}$ will be zero thus decreasing the fraction of water flowing behind the front.

The influence of the relative permeabilities of oil and water on the fraction of water flowing are more significant. Some investigators (105, 106) have shown that relative permeabilities of oil and water are significantly changed by wettability changes. As the wettability of a porous medium changes from preferentially oil-wet to water-wet, at a given water saturation, the oil relative permeability increases and the water relative permeability decreases. Therefore the permeability ratio k_w/k_o is greatly decreased. A change of wettability from oil-wet to water-wet would then decrease the fraction of water flowing at any given water saturation. Thus breakthrough recoveries and recoveries at fixed volumes of injection should be increased.

A review of the theoretical aspects of water flooding suggests that the displacement of oil from sand surfaces may be altered by simple chemicals. Theoretically, changes in interfacial tension between oil and water and wettability changes can influence the recovery of oil from porous media.

MODEL SCALING

Laboratory displacement tests must be properly designed or "scaled" to eliminate the effects of viscous fingering and capillary end effects (107, 108, 109, 110, 111, 112, 113, 114). Rapaport and Leas (115) found that capillary end effects could be eliminated if the scaling coefficient, $LV \mu_w$, was greater than a critical value of 1. The terms of the scaling coefficient are:

L = total length of flooded system (cm)

V = total flow rate per unit cross sectional area (cm/min)

μ_w = injected water viscosity (cp)

At the injection rates of 30 and 40 cubic centimeters per hour, the scaling coefficients for the system used in this study were 1.97 and 2.62 cm² cp/min. These rates were considered sufficiently high to eliminate capillary end effects.

To scale for viscous fingering effects, the scaling coefficient developed by Chuoke, et al, (116) was utilized. The scaling coefficient is:

$$\frac{\lambda_{cr}}{h} = C \sqrt{\frac{3 \sigma_{wo} K}{V (\mu_o - \mu_w) h^2}} \quad (5)$$

where λ_{cr} = critical finger distance (cm)

h = lateral dimension of core (cm)

C = dimensionless constant experimentally found to be 30

σ_{wo} = interfacial tension between oil and water (dynes/cm)

K = absolute permeability of core (cm²)

V = total flow rate per unit cross sectional area (cm/sec)

μ_o = oil viscosity (dyne-sec/cm)

μ_w = water viscosity (dyne-sec/cm)

Chuoque, et al, (117) found that if the scaling coefficient, λ_{cr}/h , is much less than one, a large number of fingers develop in the model and production behavior is insensitive to viscous fingering. If the scaling coefficient is much greater than one, no fingers would occur and production behavior is stable. If the critical finger distance is of the order of the core diameter, unstable and inconsistent production behavior might be expected. In this study the maximum viscous scaling coefficient was 0.0078, therefore, production behavior should be insensitive to fingering and the displacement tests were considered adequately scaled for viscous fingering effects.

As the results of this study were not used to predict the performance of any specific reservoir, there was no need to match laboratory scaling factors and reservoir scaling factors. However, as reservoir sands and crude oils were used during the study, wettability and capillary characteristics would be similar in the laboratory and the reservoir. Therefore, the results of the laboratory study should be applicable to reservoir performance under limited reservoir conditions.

EXPERIMENTAL EQUIPMENT

Viscosity measurements on the Lloydminster crude oils were taken with a Brookfield Viscometer with rotating spindles and a Bendix Lab-Vis meter with a calibrated probe. The probe was calibrated with standard calibrating oils and glycerine. The temperature of the crude oil was controlled by suspending the crude oil container in a constant temperature water bath during viscosity measurements.

Imbibition tests were conducted with an apparatus similar to that used and described by Bobek, Mattax and Denekas (118). Lucite cylinders fitted with 100 mesh screens at each end were used to contain the unconsolidated sands. The cylinders were two inches in length and one inch in diameter. After packing with sand the cylinders were evacuated in a vacuum cell before saturation with the saturating fluid.

A Cenco du Nuoy tensiometer Model 70545 with a platinum ring six centimeters in circumference was utilized for surface and interfacial tension measurements. Surface and interfacial tension readings were corrected using the correction factor tables of Zuidema and Waters (119).

A Beckman Model N pH meter with a glass reference electrode and a Beckman E-2 glass electrode was used for pH measurements. The Beckman E-2 glass electrode was used because it exhibits linear behavior throughout the entire pH range and shows minimum deviation in highly alkaline solutions with high sodium ion concentrations.

The core holders containing the unconsolidated sand packs during displacement tests were stainless steel models designed for high pressure flooding with corrosive chemical solutions. The internal

dimensions of the core holders were 6.00 inches length and 0.870 inches diameter. Stainless steel screens of 200 mesh were placed between the sand and the end plates to prevent shifting of the sand and plugging of the outlet lines.

The oil and water flooding apparatus shown in Figure 1 consisted of two core holders which were suspended in a constant temperature water bath thermostatically controlled to within 1° F. Pressure taps were placed immediately outside the upstream end plates of each core holder. Calibrated Heise gauges were connected to the pressure taps to measure the upstream flowing pressures. Short downstream outlets on each core minimized outlet volume corrections and eliminated the need for downstream pressure taps. Injection of fluids into each core was maintained at constant rates with a Ruska double cylindered proportioning pump. The injection rate could be varied from 10 to 1200 cubic centimeters per hour for each cylinder. The fluids produced during the displacement tests were collected in 15 millilitre centrifuge tubes. An International centrifuge was used to separate the oil and water in the produced fluid.

The cleaning and saturating apparatus, also shown in Figure 1, consisted of a core holder with pressure taps mounted immediately outside the upstream and downstream end plates. Calibrated Heise gauges were connected to the pressure taps to measure the pressure drop across the core for permeability calculations. The effluent fluids were collected in 100 millilitre graduates. The cleaning and saturating apparatus contained Varsol and brine reservoirs for cleaning and saturating the core. A vacuum pump was used to deaerate the brines and evacuate

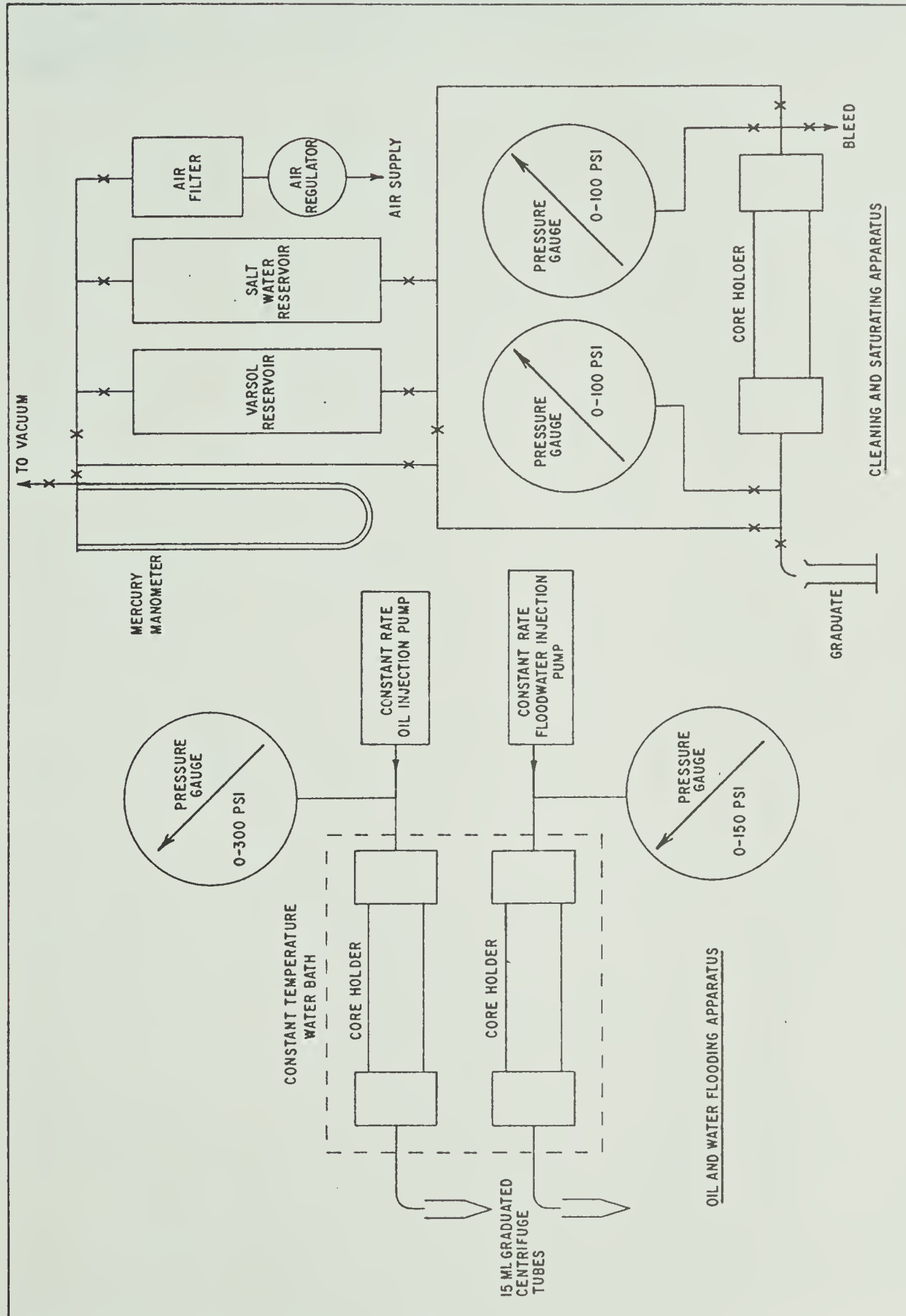


FIG. 1 - SCHEMATIC DIAGRAM OF DISPLACEMENT AND CLEANING EQUIPMENT
FOR UNCONSOLIDATED SAND CORE PACKS

the core. A regulated air supply was used to dry the core and provide a pressure source for the brine during the measurement of liquid permeability.

EXPERIMENTAL PROCEDURE

Source and Handling of Materials

Six sand samples were used during this study and are identified in Table A-1 in Appendix A. An unconsolidated sand retrieved in a rubber sleeved core from the well Fargo Husky Lone Rock A-7-9-47-27 W3M was the source of four Sparky sand samples. Sands 1 and 2 were picked from the best sand sections of the core while Sands 3 and 4 were picked from the poorer sand sections containing finer grained sand and significantly more clay. Sand 1 was cleaned using a technique similar to that described by Collins (120). The sand was washed with hot tap water and flushed with Varsol, a commercial solvent, until no further traces of oil staining were evident. After evaporating the Varsol, the sand was dried in a drying oven at 250° F for 8 hours. Sand 2 was cleaned using a technique similar to that described by Scott (121). The sand was cleaned in a Soxhlet extractor using toluene as the solvent. The sand was dried for a period of 8 hours at 250° F. Sands 3 and 4 were cleaned with successive Varsol washes until no further oil staining was evident. These sands were then dried at room temperature of approximately 70° F for two weeks until all the cleaning fluid had evaporated and the sands appeared dry. Some fines may have been lost from the sands due to the cleaning process. Sieve analyses of the sands were made after they were cleaned and dried. The +40 mesh sand and clay particles were discarded.

Sand 5 was a 20-40 mesh coarse Ottawa sand which was cleaned with hot water and dried at 250° F for 8 hours. Sand 5 was used for bench tests and imbibition tests only.

Sand 6 was an uncleaned, unconsolidated Sparky sand from the Cold Lake area. The core was recovered in a rubber sleeved core barrel and canned upon recovery. Two core packs were prepared using the uncleaned sand from the cans.

Lloydminster crude oil, treated only for the removal of water, was used for all testing. This oil is identified as Crude A in Table A-3. The crude oil gravity was 17.0° API and the basic sediment and water content was 0.1% by volume. Another crude oil sample, identified as Crude B, from the lease tank of the well Husky Maidstone A-1-11-48-23 W3M was not used because the basic sediment and water content of the crude was 7.5% by volume. The crude oil gravities were determined by the hydrometer method utilizing ASTM (122) test D287-55 and the basic sediment and water contents were determined using ASTM test D96-58T.

For bench tests and imbibition tests, two crude mixtures were made. A Varsol-crude mixture was prepared by mixing 6 parts by volume of Varsol with 1 part by volume of Crude A. An iso-octane-crude mixture was prepared by mixing 6 parts by volume of iso-octane with 1 part by volume of Crude A.

An artificial brine containing 84.839 grams of sodium chloride dissolved in sufficient distilled water to make a litre of solution was prepared. The salt concentration was identical to that used by Scott (123) who matched the chloride ion content of a Lloydminster field water sample described by Collins (124).

A complex salt solution was prepared to simulate the chemical composition of a field water sample from the well 2-24-50-2 W4M in the

Lloydminster area. The chemicals used to prepare the complex salt solution are outlined in Table A-4. The chemical analyses of the complex salt solution and the various field waters are presented in Table A-5.

The chemicals used in the preparation of various solutions were reagent grade and are identified in Table A-6. The solvents used for cleaning the sands were reagent or commercial grade. All aqueous solutions were deaerated under vacuum after mixing.

Bench Test Procedure

A simple bench test technique was used to determine qualitatively the wettability of the unconsolidated sands. A procedure similar to that proposed by Bobek, Mattax and Denekas (125) was utilized. To test for wettability, a thin layer of dry sand was spread on a glass plate. Droplets of oil or water solutions were placed on the surface of the sand. The rate of movement of the fluid into the sand as observed through a 10 power magnifying glass was recorded. To test for preferential water wettability, a thin layer of dry sand was spread on a glass plate. An oil saturation was established by adding oil to the sand. Droplets of water were then placed on the sand and the rate of water movement into the sand was observed. If the water moved readily into the sand and displaced oil from the surface of the sand grains, the sand was considered preferentially water-wet. Similarly, to test for preferential oil wettability, the dry sand was first saturated with water, then the movement of droplets of oil into the sand was observed. If the oil moved readily into the sand and displaced water from the sand, the sand was considered preferentially oil-wet. If oil was not

imbibed by the sand saturated with water and water was not imbibed by the same sand saturated with oil, the wettability of the sand was considered to be neutral.

Cell Imbibition Tests

Cell imbibition tests were conducted using the procedure described by Bobek, Mattax and Denekas (126). An imbibition cell was fitted with a 100 mesh screen on one end. Unconsolidated sand was poured into the open end of the cell and packed by tapping the bottom of the cell until no further compaction was visually discernible. The upper end of the cell was then fitted with a 100 mesh screen and the assembled cell was weighed. The cell was evacuated in a vacuum cell and saturated while under vacuum with a saturating fluid. The saturated cell was weighed and the weight of the saturating fluid was determined by weight difference. The porosity of the sand in the cell was calculated from volumetric determinations of the saturating fluid and the cell.

The saturated cell was placed in a vertical position in the imbibition apparatus and the fluid to be imbibed was introduced into the apparatus until the cell was completely immersed. The volume of saturating fluid displaced from the cylinder by the imbibed fluid was measured in the imbibition apparatus and recorded as a function of time. Fresh fluids and clean sands were used during successive imbibition tests. The imbibition tests were terminated when the volume of saturating fluid displaced showed little or no change over a period of a few hours. Imbibition tests were conducted at room temperature of approximately 75° F.

Interfacial Tension Test Procedure

The du Nuoy tensiometer was used to measure the interfacial tension between brine solutions and crude oil. The standard method of testing for interfacial tension of oil against water by the ring method ASTM test D971-50 was utilized. The temperature of the fluids during interfacial tests was maintained within 3° F for each set of tests. The temperature range for the complete series of tests was 75° F to 81° F. The measured interfacial tension readings were corrected using the density corrections of Zuidema and Waters (127) in graphical form. Due to the difficulty in determining the breaking point of the water film at low interfacial tension values, values less than 0.4 dynes per centimeter were not considered reliable. These readings were simply recorded as less than 0.4 dynes per centimeter.

Core Packing and Core Properties

After the empty core holders were weighed on a sensitive beam balance they were packed with dry sand using the following method. The downstream end of the core holder, fitted with a 200 mesh screen, was screwed on the core holder tube. The core holder was placed in a vertical position and batches of about 10 cubic centimeters of sand were poured into the open end of the tube. Each batch of sand was tamped with a 5/8 inch diameter steel rod and the downstream end of the core holder was tapped with a plastic mallet to compact the sand. The procedure was repeated until the core holder was full and no further compaction of the sand was evident when tapping the downstream end of

the core holder. The upstream end of the core holder, fitted with a 200 mesh screen, was then screwed on the core holder tube.

The packed core holder was weighed and mounted in the cleaning and saturating apparatus shown in Figure 1. The core was evacuated and saturated with artificial brine. The liquid permeability was determined by flowing a measured volume of brine through the core while recording the pressure drop across the core and calculating the permeability by applying the Darcy linear flow equation. The saturated core was then re-weighed and the volume of the brine in the core was calculated. The pore volume of the core was equivalent to the volume of brine in the core. Knowing the bulk volume of the core holder, 58.4 cubic centimeters, and the weight of sand in the core holder, the porosity of the core, sand grain volume and sand density were calculated.

After measuring the core properties, the core was mounted in the oil and water flooding apparatus of Figure 1. The core was then flooded with Lloydminster crude oil at the rate of 30 or 40 cubic centimeters per hour. Two pore volumes of oil were injected into the core to ensure that an irreducible water saturation was attained. The volume of brine produced during the oil flood was measured and the initial water saturation was calculated based upon brine remaining in the core.

The oil saturated core was now ready for water flooding. The core was flooded with brine or chemical-brine solutions at a constant injection rate of 30 or 40 cubic centimeters per hour. The produced and often emulsified fluids were recovered in 15 millilitre centrifuge tubes. The fluid was centrifuged to reproducible readings of oil and water recovery. Thus oil recovery and core saturations could be deter-

mined by a material balance on the effluent fluids. All displacement tests were conducted at 80° F.

The pressure performance of both oil and water floods was recorded. During the oil flood, the pressure drop across the core at irreducible water saturation was recorded and used to determine the pressure drop ratio during the subsequent water flood. For each core, the period of time from initial saturation with water to oil flooding and the period of time from oil flooding to water flooding was recorded.

With the exception of four displacement tests, the core holders were repacked with clean sand after water flooding. The sand from the water flooded cores was discarded to eliminate the possibility that properties of the core, such as wettability, might have been altered by a previous test. The four displacement tests which used previously flooded cores are noted in Appendix C. Displacement tests 3 and 4 used the uncleaned cores from displacement tests 1 and 2 respectively. Displacement tests 8 and 9 used the cleaned cores from displacement tests 6 and 7 respectively. These two cores were cleaned by flushing with many pore volumes of Varsol until no oil staining in the effluent was evident. The cores were dried by flowing air through them for a week.

Two cores were packed with Sand 6, the uncleaned unconsolidated Sparky sand from the Cold Lake area. During water flooding with brine, both cores plugged and no effluent was produced. No further attempt was made to test this sand.

Following a conventional brine flood, the core used in displacement test 9 was flooded with a 0.1 percent sodium hydroxide in brine solution to determine if additional oil recovery was possible

from a water flooded core.

The cores prepared for displacement tests 65, 66 and 67 were saturated with field water instead of brine. These cores were then flooded with 0.1 percent sodium hydroxide in brine solution to determine if precipitation of calcium and magnesium hydroxides within the cores would cause core plugging.

EXPERIMENTAL RESULTS

Sand and Fluid Properties

The sands used in this study are identified in Table A-1 and sieve analyses of the four Sparky sand samples are presented in Table A-2. The particle size distribution of the Sparky sands is shown in Figure 2. Sands 1 and 2 appear to be similar in particle size distribution while sands 3 and 4 contain significantly higher percentages of very fine grained sand and clay particles of -200 mesh size. Sand 5, the Ottawa sand, was considered to be water-wet (128).

The Sparky sand has been described (129) as the second sand from the top of the Mannville formation in the Lloydminster area underlying the Colony sand. It is a petroliferous, unconsolidated, well sorted, round pure quartz sand with average grain size of 0.5 millimeter. Commonly it is associated with pyrite nodules and grey shales having some plant fragments and is approximately 40 feet thick in the Lloydminster area.

The properties of two Lloydminster crude oil samples are shown in Table A-3. Crude A, which contained a minimal amount of water, was used exclusively in this study. Measurements of the viscosity of Crude A with a Brookfield rotating viscometer indicated that the viscosity decreased as the length of time of agitation of the sample increased. The decrease in viscosity was considered to indicate non-Newtonian properties of the crude. The viscosity of the crude oil at 80° F was 940 centipoises as measured using a Bendix Lab-Vis vibrating probe viscometer.

The viscosity of Crude B which contained 7.5 per cent water by

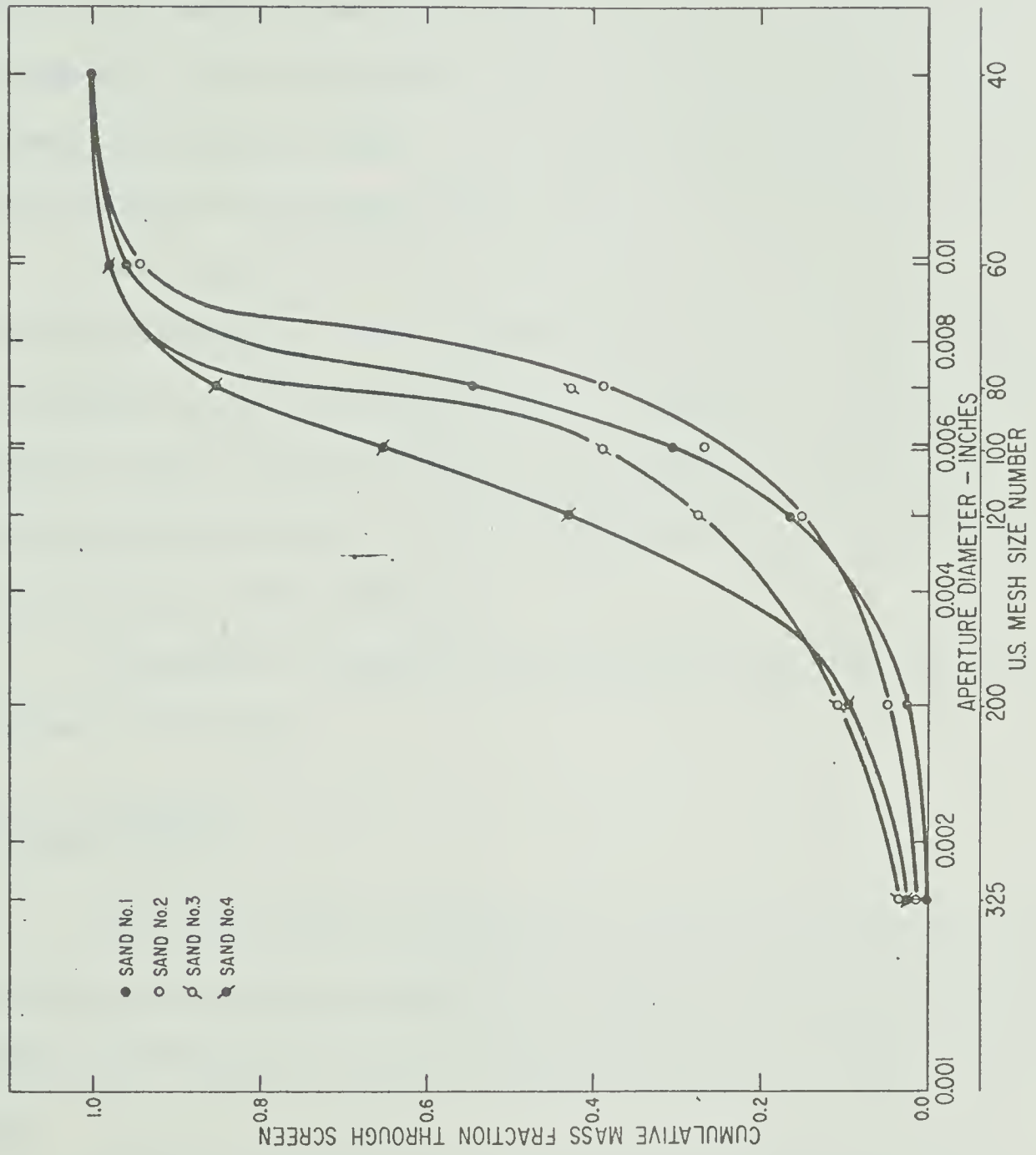


FIG. 2 - PARTICLE SIZE DISTRIBUTION OF SPARKY SANDS USED FOR CORE PACKING AND TESTING

volume was significantly higher than the viscosity of the relatively water-free Crude A sample. The increased viscosity may be attributed to the emulsified state of the crude oil (130).

The viscosities of the prepared Varsol-crude and iso-octane-crude mixtures were 1.08 and 0.414 centipoises respectively. These mixtures were used for bench tests and cell imbibition tests instead of high viscosity crude oil in order that the viscous effects of the crude oil would be eliminated (131). By using these mixtures, the viscosities of the hydrocarbon and aqueous phases were of the same magnitude.

The properties of the aqueous fluids used in the study are summarized in Table A-4. The chemical analyses of the prepared complex salt solution and various field waters are presented in Table A-5. A comparison of the chemical analyses of the complex salt solution and the field water from well 2-24-50-2 W4M indicates a good match of the chemical content of the solutions.

The names and formulas of the chemicals used in this study are given in Table A-6.

Bench Test Results

The bench tests of imbibition of various fluids into dry and fluid saturated sands are summarized in Table B-1. These tests provided a simple qualitative evaluation of the wetting characteristics of the sands.

Varsol and the Varsol-crude mixture were spontaneously imbibed by all dry sands. Brine and chemical-brine solutions were spontaneously imbibed by dry Ottawa sand. Therefore, Ottawa sand could be

wetted by either the hydrocarbon mixtures or the aqueous solutions. Brine and chemical-brine solutions were slowly imbibed by Sands 1 and 2 and not imbibed by Sands 3 and 4. Therefore, while the Sparky sands were wetted by the hydrocarbon mixtures, they were not readily wetted by the aqueous solutions.

Varsol and the Varsol-crude mixture were spontaneously imbibed by all sands initially saturated with aqueous solutions. However, brine was not imbibed by sands initially saturated with the Varsol-crude mixture. This indicated that all sands were preferentially wetted by the Varsol-crude mixture.

Some chemical-brine solutions were imbibed by sands initially saturated with the Varsol-crude mixture. Therefore, the wettability of the sands was changed from preferentially oil-wet to preferentially water-wet by the addition of chemicals to the brine. The chemicals which caused wettability reversal were NaOH, Na_2CO_3 , KOH and Na_3PO_4 . The other chemicals, Na_4 EDTA, $\text{Na}_4\text{P}_2\text{O}_7$, $(\text{NaPO}_3)_6$ and $\text{Na}_5\text{P}_3\text{O}_{10}$ were not as effective in changing the wettability characteristics of the sands.

Brine was spontaneously imbibed by Ottawa sand saturated with Varsol, yet brine was not imbibed by the same sand saturated with the Varsol-crude mixture. Some constituents of Lloydminster crude oil changed the wettability characteristics of the normally preferentially water-wet Ottawa sand to preferentially oil-wet.

Results of the bench tests, while qualitative in nature, indicated that the Sparky sand samples were preferentially oil-wet. The ability of Lloydminster crude to change the wetting characteristics of Ottawa sand was demonstrated. This simple test technique may be useful

in screening chemicals that may be considered for increasing waterflood recovery.

Cell Imbibition Test Results

The results of the cell imbibition tests are summarized in Tables B-2 and B-3. The imbibed fluid saturations are shown in Figure 3 as a function of imbibition time. This figure includes only the tests in which significant amounts of fluids were imbibed by the sand.

Imbibition tests of sands saturated with iso-octane or Varsol indicated that brine was readily imbibed by Sand 5, the Ottawa sand, but insignificant volumes of brine were imbibed by the Sparky sand samples. Imbibition tests of sands saturated with brine showed that small amounts of Varsol were imbibed by all sands except Sand 2. Therefore, the results of the imbibition tests with interfacially neutral fluids such as Varsol, iso-octane and brine indicated that the Ottawa sand was preferentially water-wet and the Sparky sands were preferentially oil-wet.

Little imbibition of brine by Ottawa sand saturated with the Varsol-crude mixture was evident. Therefore, the wettability characteristics of the sand were changed from preferentially water-wet to neutral or preferentially oil-wet by contact with the Varsol-crude mixture. There was no imbibition of brine into Sparky sands saturated with the Varsol-crude mixture. This was consistent with the previously established preferentially oil-wet characteristic of the Sparky sands.

A solution of 1 per cent sodium hydroxide in brine was readily imbibed by Ottawa sand saturated with the Varsol-crude mixture. The

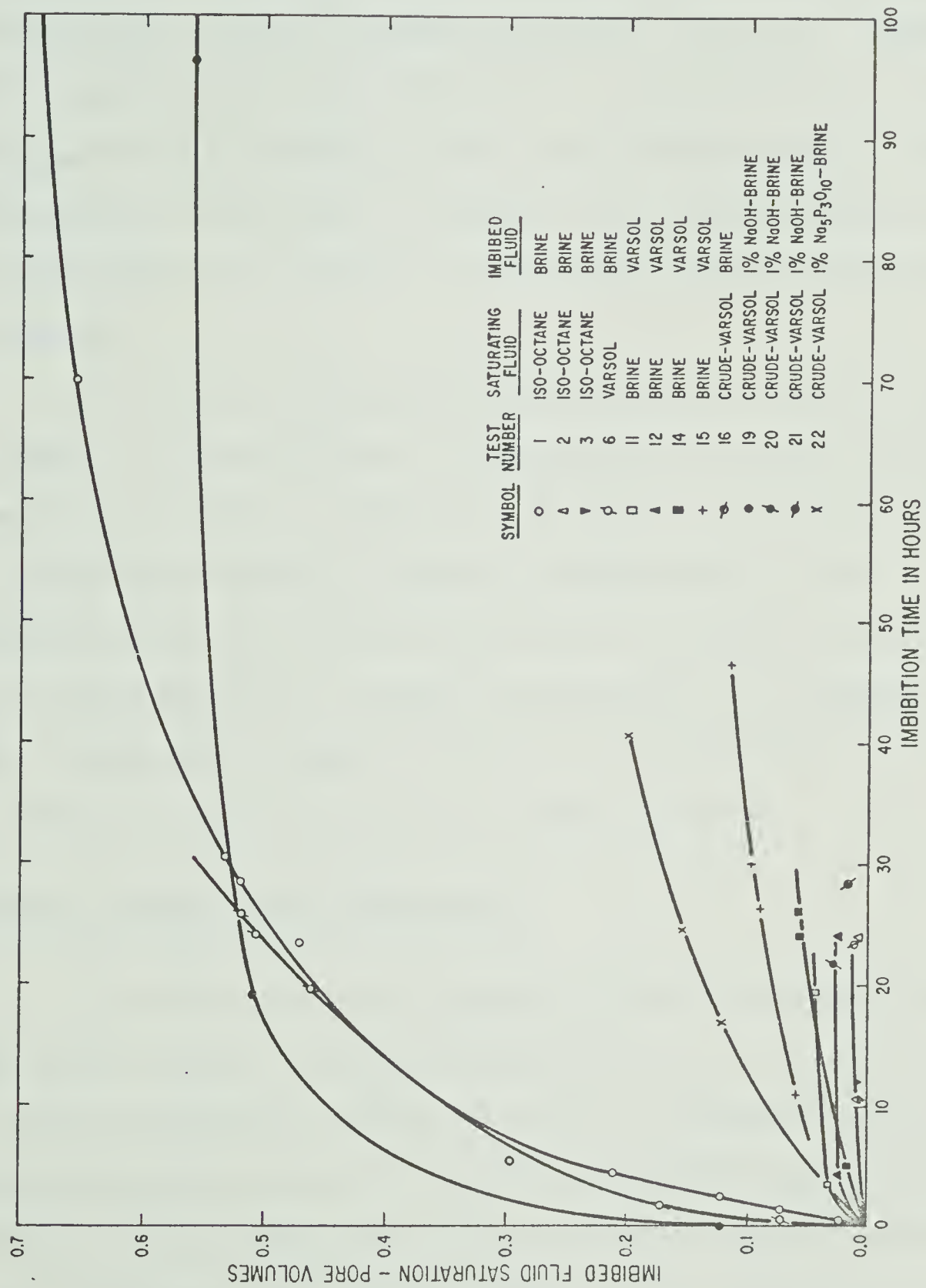


FIG.3 - IMBIBITION TEST RESULTS RELATING TO SAND WETTABILITY

Sparky sands saturated with the Varsol-crude mixture imbibed small amounts of 1 per cent sodium hydroxide in brine solution. The wettability of the sand was reversed from preferentially oil-wet to preferentially water-wet by the addition of sodium hydroxide to the brine. Compared to the 1 per cent sodium hydroxide solution, a solution of 1 per cent $\text{Na}_3\text{P}_5\text{O}_{10}$ in brine was imbibed by Ottawa sand saturated with the Varsol-crude mixture at a lower rate. Therefore, the chemical $\text{Na}_5\text{P}_3\text{O}_{10}$ reversed the wettability of the core but at a slower rate than the sodium hydroxide solution.

The results of the cell imbibition tests are consistent with the results of the bench tests. The wettability of the sands was influenced by the fluids in contact with the sands. Lloydminster crude oil changed the wettability of sands to preferentially oil-wet. The wettability of the sands could be reversed by the addition of chemicals such as sodium hydroxide or sodium tripolyphosphate to the imbibed solution. The Sparky sand samples appeared to be preferentially oil-wet when exposed to neutral fluids such as Varsol and brine.

Interfacial Tension and pH Measurements

The effect of various chemicals on interfacial tension was measured for a number of aqueous solutions and oils. The results of the tests are presented in Tables B-6 to B-24. The aqueous solution pH readings have been corrected for the effect of sodium ions and the interfacial tension readings have been corrected for ring size and fluid density differences. In a limited number of tests, the surface tension of the aqueous phase was recorded. Visual observation of precipitate in the aqueous solution was recorded.

The effect of sodium hydroxide concentration on interfacial tension is shown in Figure 4. The interfacial tension between Varsol and brine or iso-octane and brine was not significantly affected even at very high sodium hydroxide concentrations. Both Varsol and iso-octane exhibited neutral interfacial properties. However, the interfacial tension between Lloydminster crude oil and brine decreased rapidly to an immeasurably low value less than 0.4 dynes/cm at a sodium hydroxide concentration of 0.005 per cent by weight in the brine. The same low value of interfacial tension between Lloydminster crude oil and distilled water was attained at a sodium hydroxide concentration of 0.1 per cent which is a concentration 200 times greater than required in a brine solution. The significant difference in sodium hydroxide concentrations required to reach the same interfacial tension can only be attributed to the sodium chloride in the brine solution. Sodium chloride significantly reduced the amount of sodium hydroxide required to reach a given reduced level of interfacial tension.

The interfacial tension behavior between crude oil and the complex salt solution and between crude oil and field water were similar in nature. In both tests, the interfacial tension was reduced to about 16 dynes/cm at a sodium hydroxide concentration of about 0.005 per cent. Then, in both tests, the interfacial tension remained relatively constant until the sodium hydroxide concentration exceeded 1 per cent. After this concentration was reached, the interfacial tension dropped to a very low value at a sodium hydroxide concentration of 10 per cent. Visual observation of the aqueous phase during these tests indicated that a white precipitate formed at very low sodium hydroxide concentra-

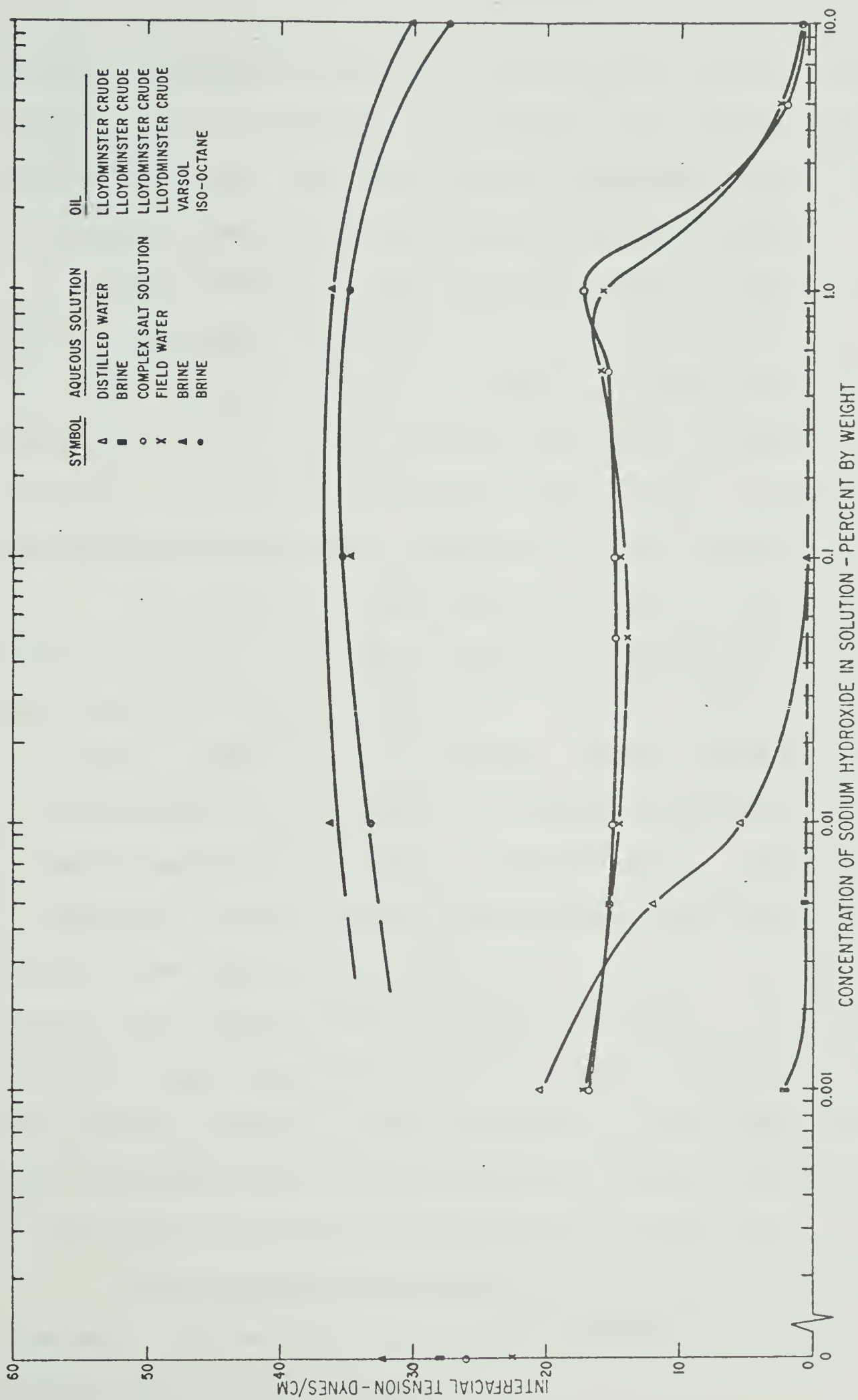


FIG.4 - INFLUENCE OF NaOH CONCENTRATION ON INTERFACIAL TENSION

tions. Subsequent testing indicated that the precipitate was calcium hydroxide and magnesium hydroxide. The interfacial tension between crude oil and the two formation water samples was not reduced to a very low value until a sufficient amount of sodium hydroxide was added to precipitate the calcium and magnesium in the water samples.

The interfacial tension test results shown in Figure 4 for solutions containing sodium hydroxide were similar in nature to the interfacial tension test results for solutions containing other chemicals. The test results for the other chemicals are shown in Figures B-7 to B-12 inclusive. Duplicate tests utilizing a greater number of sodium hydroxide concentrations are shown in Figures B-4 to B-6 inclusive.

The effect of sodium hydroxide on the pH of various solutions is shown in Figure 5. The pH of solutions of sodium hydroxide in brine and sodium hydroxide in distilled water increased steadily as the concentration of sodium hydroxide increased. However, the pH of solutions of sodium hydroxide in the complex salt solution and in field water increased to and remained constant at approximately 10. The pH rose above 10 only when the sodium hydroxide concentrations approached 1 per cent. The pH of the complex salt solution and the field water attained the pH levels of the distilled water and brine solutions only at high sodium hydroxide concentrations in excess of 2 per cent. The pH of the complex salt solution and the field water appeared to increase above 10 only when sufficient sodium hydroxide was added in excess of that required to precipitate the calcium and magnesium ions in the water.

Similar pH results were noted for solutions containing other chemicals. The test results for the other chemicals are shown in Figures B-13 to B-18 inclusive.

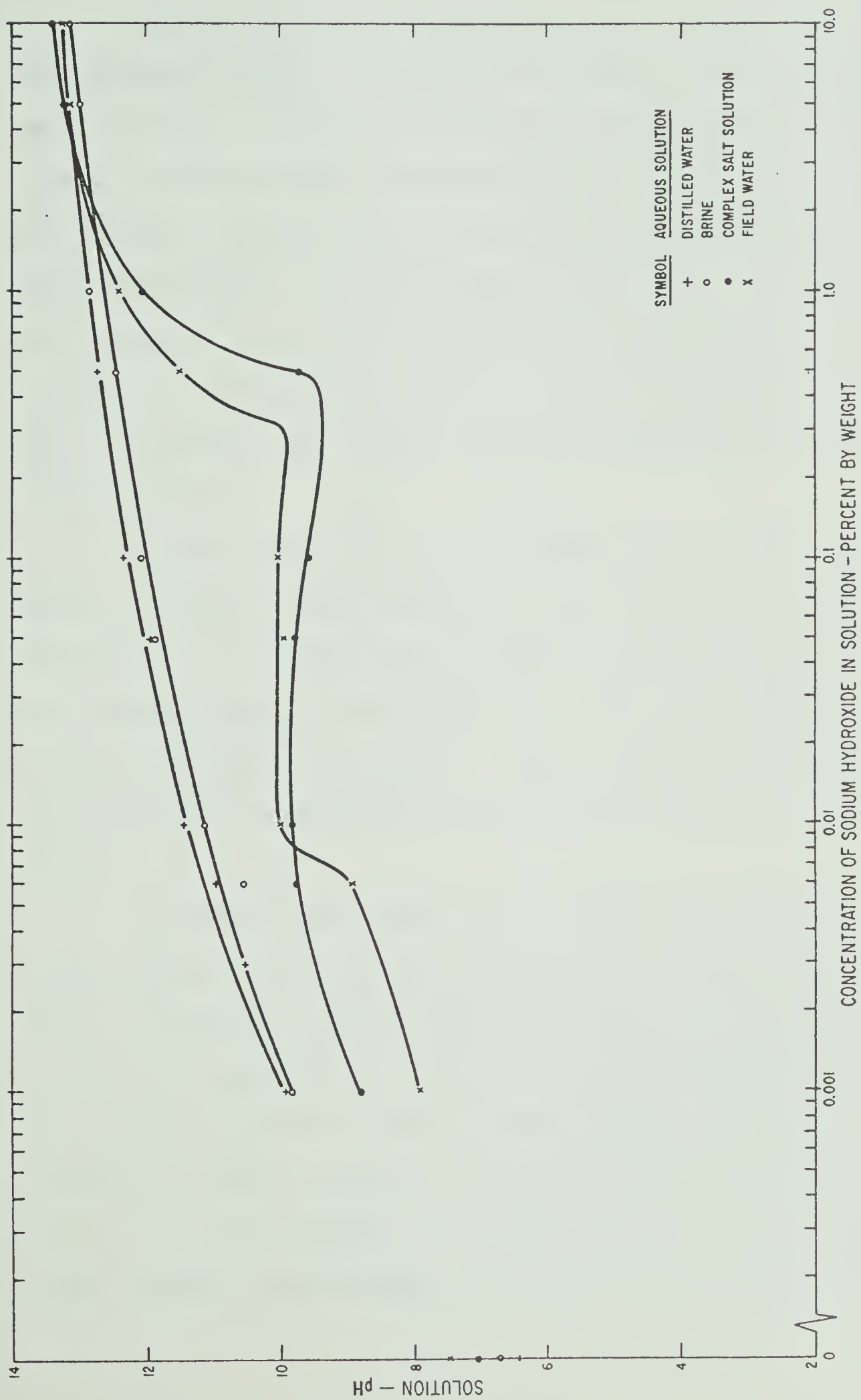


FIG. 5 - INFLUENCE OF SODIUM HYDROXIDE CONCENTRATION ON THE pH OF VARIOUS SOLUTIONS

Figure 6 shows the relationship between aqueous solution pH and interfacial tension. This figure shows that for brine and distilled water solutions, a reduction in interfacial tension between Lloydminster crude oil and the solution correlated with an increase in the solution pH. However, for the brine solution, the interfacial tension was reduced to essentially zero at a pH value of 10 while for the distilled water solution, the pH at the same interfacial tension was 12. This indicates that the presence of sodium chloride in the aqueous solution has a significant effect on the interfacial properties between the oil and the solution.

Figure 6 shows that the interfacial tension between crude oil and solutions of sodium hydroxide in the complex salt solution and field water is not reduced below 15 dynes/cm until the pH of the solution has been raised to approximately 12. Then the interfacial tension drops rapidly as the pH increases. However, when the interfacial tension was reduced to essentially zero, the pH of these solutions was over 13.

A similar relationship between solution pH and interfacial tension was noted for solutions containing KOH as shown in Figure B-19. One chemical, Na_4 EDTA, exhibited slightly different behavior as shown in Figure B-20. For the brine and distilled water solutions, the behavior was similar to that of other chemicals, inasmuch as the interfacial tension was reduced to a value of essentially zero at a pH value of 11 for the distilled water solution and 9.5 for the brine solution. However, for the complex salt solution and the field water, the

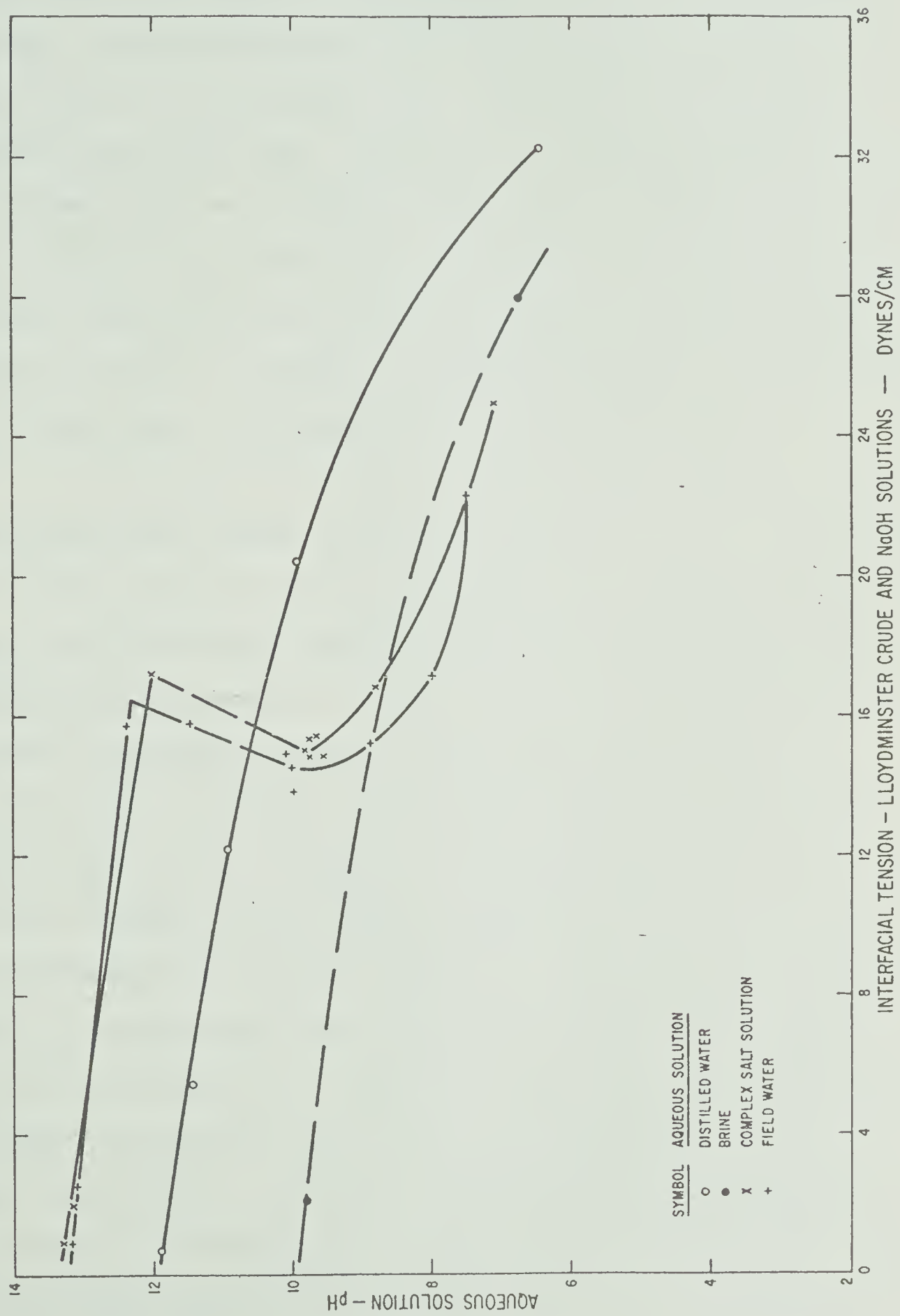


FIG.6 - RELATIONSHIP OF AQUEOUS SOLUTION pH AND INTERFACIAL TENSION FOR VARIOUS SOLUTIONS

characteristic increase in pH was absent and the pH at an interfacial tension approaching zero was approximately the same as for the brine solution. No precipitate was observed when Na_4EDTA was added to the complex salt solution and field water. This chemical inactivates or "chelates" some metal ions. Chelation is a reversible reaction between a polyvalent metal and a chelating agent to form a complex in which the metal is held by two or more bonds. The metal is thus inactivated and prevented from entering into its normal reactions, although the chelate remains in solution. Therefore, by chelating the calcium and magnesium ions, these metals were prevented from forming precipitates.

The formation of a precipitate when sodium hydroxide was added to field waters from the Lloydminster field was noted by Scott (132). To determine the nature of the precipitate and its effect on the interfacial properties between Lloydminster crude oil and formation waters containing sodium hydroxide, a complex salt solution was prepared with a chemical composition similar to a water sample from the well 2-24-50-2 W4M. The chemical content of the complex salt solution is shown in Table A-4 and a comparison of the chemical content of the complex salt solution with the chemical compositions of field waters from the Lloydminster area is made in Table A-5. Figures 4, 5 and 6 illustrate that the behavior of the complex salt solution is very similar to that of the field water. Therefore, the behavior of the field water is probably controlled by one or more of the simple chemicals in the complex salt solution. To determine which chemicals most influenced the behavior of the complex salt solution, solutions were prepared with the individual chemicals in the complex salt solution. Each of the

chemicals were tested. The results of the tests are tabulated in Tables B-8 to B-13 and illustrated in Figures B-1 to B-3. These tests indicated that the behavior of the complex salt solution was most influenced by the calcium content and to a lesser degree by the magnesium content. When sodium hydroxide was added to solutions containing these chemicals, white precipitate formed. This would indicate that the precipitates were calcium hydroxide and magnesium hydroxide. Both of the chemicals have a low solubility in water. It is likely that the precipitate that forms when sodium hydroxide is added to field water is a combination of calcium hydroxide and magnesium hydroxide.

Displacement Test Results

A summary of the displacement test results is presented in Tables C-1 to C-3. The results of the individual tests are presented in Tables C-4 to C-65.

The porosities, permeabilities and initial water saturations of displacement test cores ranged from 39.7 to 48.0 per cent, 3.27 to 12.3 darcies and 9.3 to 16.0 per cent respectively.

A number of tests were conducted with brine as the injected fluid to test the flooding equipment and testing procedure. Displacement tests 1 and 2 were conducted and the flooded-out cores were re-saturated with oil. After resaturation, the initial water saturations increased from 12.7 and 13.0 per cent to 33.9 and 33.2 per cent respectively. Displacement tests 3 and 4 were carried out on the resaturated cores and, while oil recovery in pore volumes was similar to the initial two tests, the recovery in terms of initial oil-in-place was 13 to 21

per cent higher due to the increased initial water saturation. Because initial core conditions could not be reproduced by resaturating flooded-out cores, all subsequent displacement tests were conducted using clean sand. A number of subsequent displacement tests indicated that initial saturation conditions and recovery behavior were similar for cores packed with similar sands and saturated for similar lengths of time.

The period of water saturation as shown in Table C-2 was defined as the period of time from the moment the core was initially saturated with water until the core was flooded with oil to establish simulated reservoir conditions. The period of oil saturation was defined as the period of time from the moment the core was oil flooded until the core was water flooded to determine oil recoveries.

Early displacement tests indicated that the periods of water and oil saturation might influence the recovery performance of the cores. For example, the periods of water and oil saturation were 1 and 24 days respectively for test 18, and 24 and 2 days respectively for test 19. The injected fluid in both tests was a solution of 0.005 per cent sodium hydroxide in brine. However, the oil recovery at water breakthrough was 0.12 and 0.175 pore volumes respectively for tests 18 and 19 while oil recovery at five pore volumes injected was 0.294 and 0.340 pore volumes respectively. The differences in recoveries indicated that the periods of saturation may have influenced the performance. Therefore, the periods of water and oil saturation were held constant at zero days for tests 23 to 34. Oil flooding of the core immediately followed saturation of the core with water and water flooding of the core immediately followed oil flooding. For tests 35 to 64 the periods

of water and oil saturation were one day.

A brine base flood defined the performance of each sand for each set of saturation periods. All other chemical floods were compared to the base flood in order to evaluate the effectiveness of the chemicals in recovering oil. Test 23 was the brine base flood for Sand 1 with a period of saturation of zero days. Similarly, test 36 was the base flood for the same sand with a period of saturation of one day.

Figure 7 illustrates the increase in oil recovery resulting from the addition of sodium hydroxide to the injected brine. Test 23, the base flood, exhibited a low oil recovery of 0.10 pore volume of oil at water breakthrough. Oil recovery after breakthrough, or subordinate production, was significant and oil recovery at five pore volumes injected was 0.391 pore volume of oil. The low breakthrough recovery and significant subordinate production after breakthrough were characteristic of brine floods.

Both breakthrough recovery and oil recovery at five pore volumes injected were significantly increased when sodium hydroxide was added to the injected brine. For test 27, during which the injected brine contained 0.1 per cent sodium hydroxide, oil recovery at water breakthrough was 0.21 pore volumes and at five pore volumes injected was 0.589 pore volumes. Similarly, for test 31, during which the injected brine contained 1 per cent sodium hydroxide, oil recovery at water breakthrough was 0.225 pore volumes and at five pore volumes injected was 0.617 pore volumes. Compared to test 23, the base flood recoveries at breakthrough and five pore volumes injected for tests 27 and 31 were significantly higher as a result of the sodium hydroxide

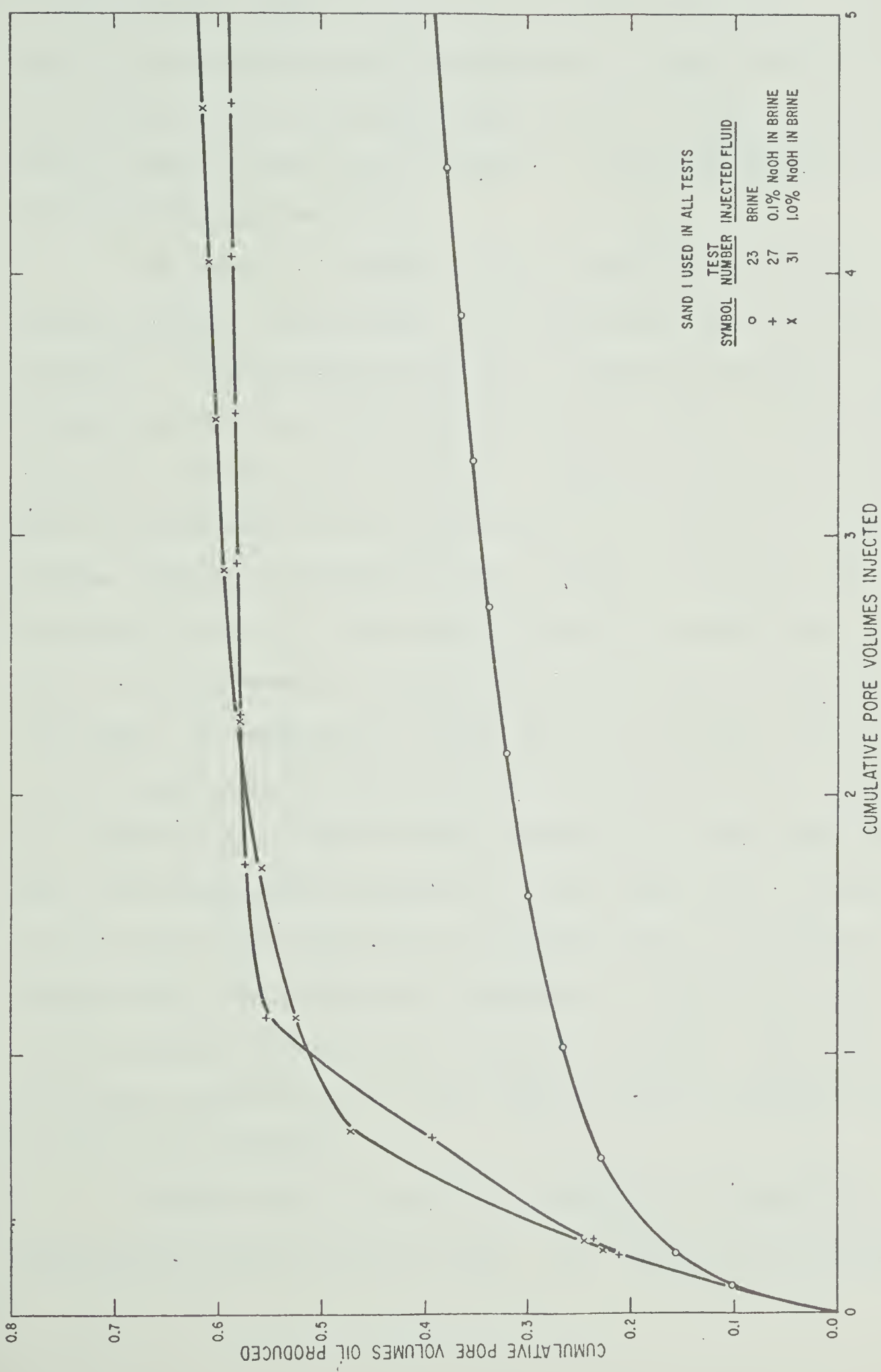


FIG.7-7- OIL RECOVERY OF SODIUM HYDROXIDE IN BRINE SOLUTION DISPLACEMENT TESTS — SAND I

in the injected brine. Most of the successful chemical floods were characterized by higher oil recoveries at water breakthrough, a high rate of oil production after breakthrough and a sharp reduction in the oil production rate after approximately one pore volume of injection. For the series of tests shown in Figure 7, the periods of water and oil saturation were zero days.

The results of a series of displacement tests with varying sodium hydroxide concentrations in the displacing brine are shown in Figure 8. Little change was observed in breakthrough recovery or oil recovery at five pore volumes injected when the sodium hydroxide concentration was less than 0.1 per cent. Breakthrough recovery for test 36, the base flood, was 0.125 pore volume and oil recovery at five pore volumes injected was 0.390 pore volume. However, recoveries were significantly increased at higher sodium hydroxide concentrations. For test 51, during which the injected brine contained 0.1 per cent sodium hydroxide, the breakthrough recovery was 0.21 pore volume and recovery at five pore volumes injected was 0.595 pore volume of oil. For test 54, during which the injected brine contained 1 per cent sodium hydroxide, the breakthrough recovery was 0.25 pore volume and oil recovery at five pore volumes injected was 0.554 pore volume. From Figure 8, it appears that a sodium hydroxide concentration of less than 0.1 per cent in the injected brine has little effect upon recovery. For sodium hydroxide concentrations of 0.1 per cent and over, the increase in oil recovery was significant.

For the series of tests shown in Figure 8, the periods of water and oil saturation were one day. Oil recovery at water break-

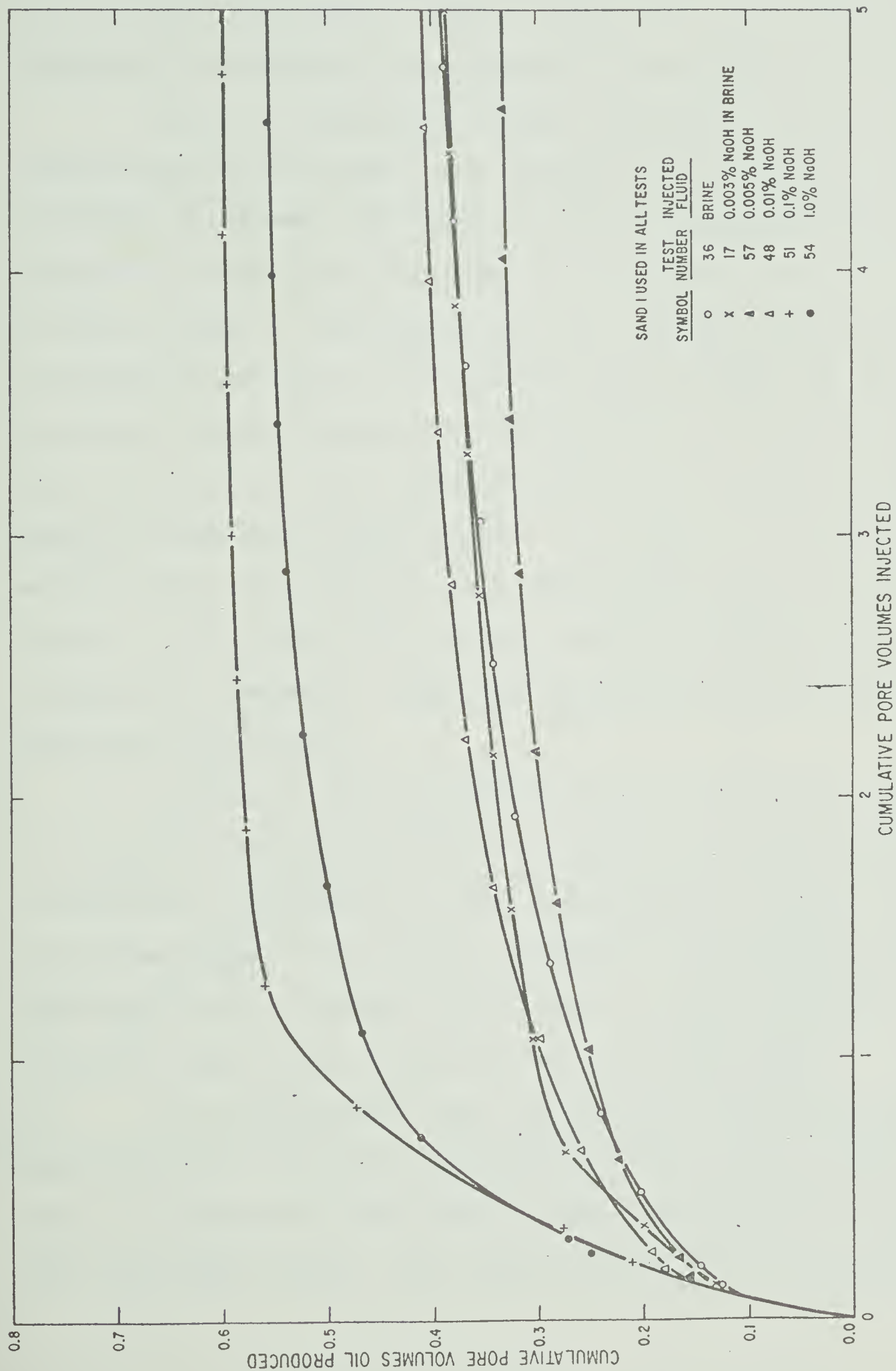


FIG.8- INCREASE IN OIL RECOVERY DUE TO SODIUM HYDROXIDE IN BRINE SOLUTION DISPLACEMENT TESTS-SAND I

through and at pore volumes injected were essentially the same for both series of tests illustrated in Figures 7 and 8. The time of water saturation and oil saturation did not appear to have an effect on recovery.

During the displacement testing, the pressure drop across the core was measured and recorded. The pressure drop ratio was calculated by dividing the pressure drop across the core at a given cumulative pore volume of oil produced by the pressure drop at the end of the oil flood. As shown in Figure 9, the pressure drop ratio decreased rapidly as oil was produced during test 36, the brine base flood. Because the viscosity of the injected water was very much less than the viscosity of the crude oil within the core, the pressure drop across the core decreased rapidly as water moved through the core. As a result of the adverse mobility ratio, oil recovery at water breakthrough was low in the base floods. As the pressure drop decreased rapidly, the driving force moving the oil diminished. After water breakthrough, water-oil ratios were high for base floods.

It was noted that the pressure drop did not decrease as rapidly during tests conducted with brines containing high sodium hydroxide concentrations. The pressure drop ratio was sustained at higher levels for a given volume of oil produced. The mobility of the injected phase appeared to have been reduced and oil recovery at water breakthrough and at five pore volumes of injection was substantially higher.

In two displacement tests, the sustained pressure drop ratio was particularly noticeable. The results of these tests are shown in Figure 10 in which the pressure drop is shown as a function of cumulative pore volumes injected. The pressure drop ratio for the brine base

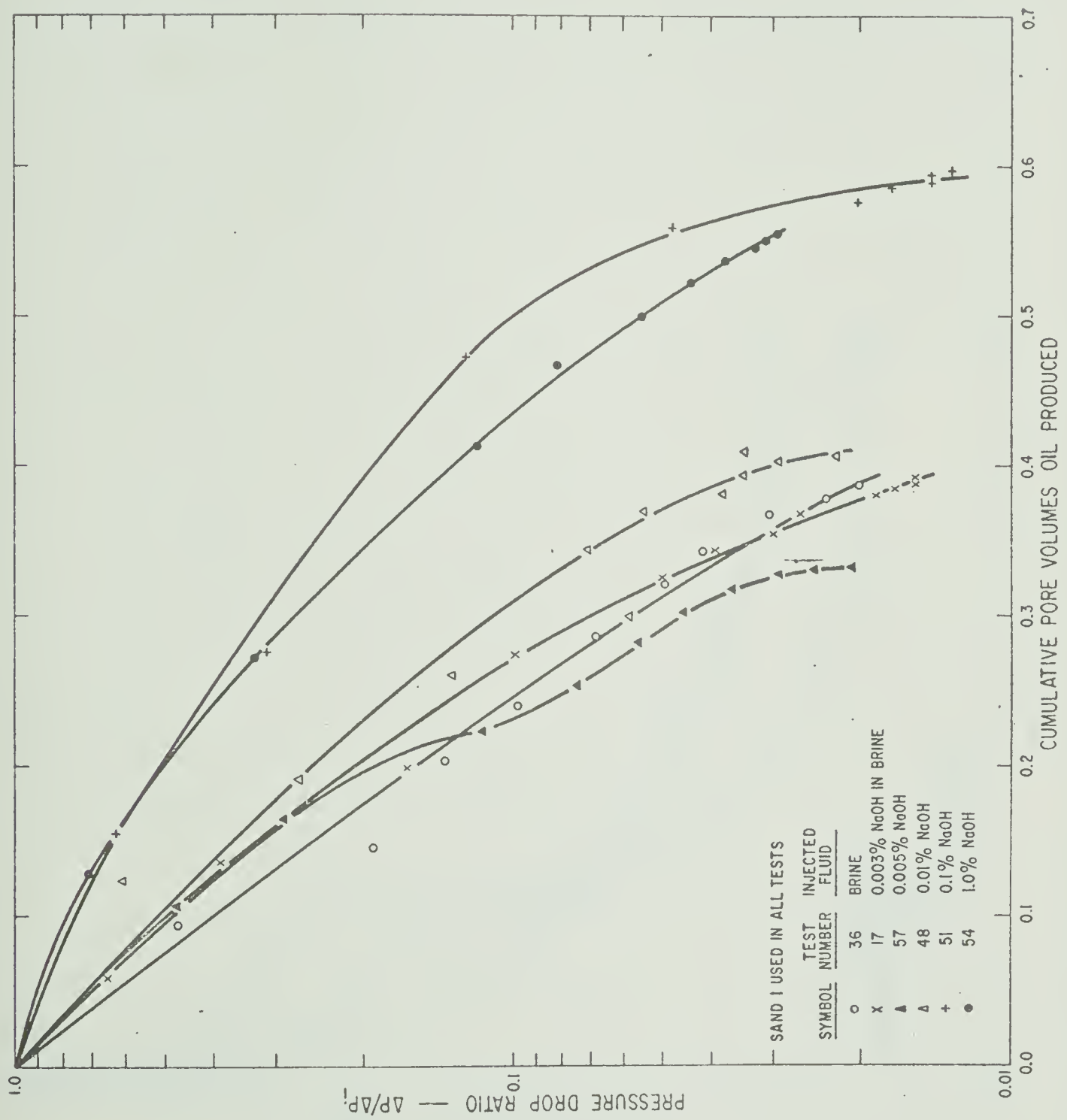


FIG.9 - PRESSURE BEHAVIOUR FOR SODIUM HYDROXIDE IN BRINE SOLUTION DISPLACEMENT TESTS —SAND 1

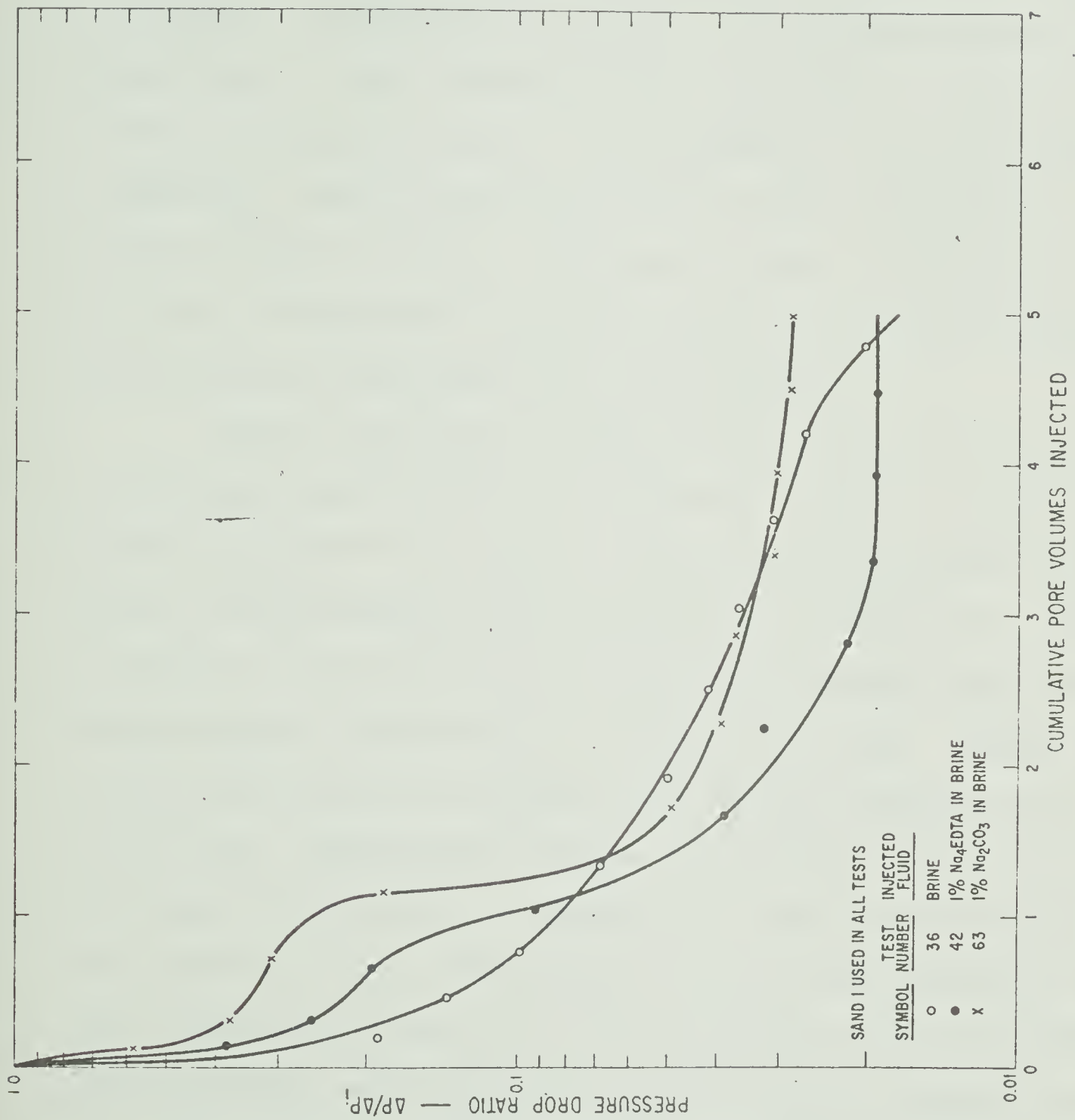


FIG.10 - PRESSURE BEHAVIOUR RELATIONSHIP WITH PORE VOLUMES INJECTED
FOR CHEMICAL IN BRINE SOLUTION DISPLACEMENT TESTS—SAND 1

flood, test 36, decreased rapidly as injection progressed. However, the pressure drop ratios during tests 42 and 63 decreased at a slower rate and dropped sharply only after more than one pore volume had been injected. Oil recoveries at breakthrough for tests 42 and 63 were 0.125 and 0.25 pore volumes respectively as compared to 0.125 pore volumes for test 36. Oil recoveries at one pore volume injected for tests 42 and 63 were 0.573 and 0.499 pore volumes respectively as compared to 0.260 pore volumes for test 36. Oil recoveries at five pore volumes injected for tests 42 and 63 were 0.741 and 0.566 respectively as compared to 0.390 for test 36. During tests 42 and 63, a large part of the total oil recovered was produced during the injection of the first pore volume when the pressure drop ratios were high.

Figure 11 shows the influence of sodium hydroxide concentration in the injected brine on oil recovery for a number of displacement tests using Sand 1. Oil recovery at water breakthrough begins increasing at a sodium hydroxide concentration of about 0.003 per cent. Oil recovery at one and five pore volumes injected increases sharply between sodium hydroxide concentrations of 0.01 and 0.1 per cent. Maximum oil recovery was achieved at a minimum sodium hydroxide concentration of 0.1 per cent. Higher sodium hydroxide concentration in the brine did not result in the recovery of additional oil. For base floods the average recoveries at water breakthrough, one pore volume injected and five pore volumes injected were 0.11, 0.27 and 0.39 pore volumes respectively. For 0.1 per cent sodium hydroxide in brine floods, the average recoveries at water breakthrough, one pore volume injected and five pore volumes injected were 0.22, 0.48 and 0.59 pore volumes respectively. Therefore,

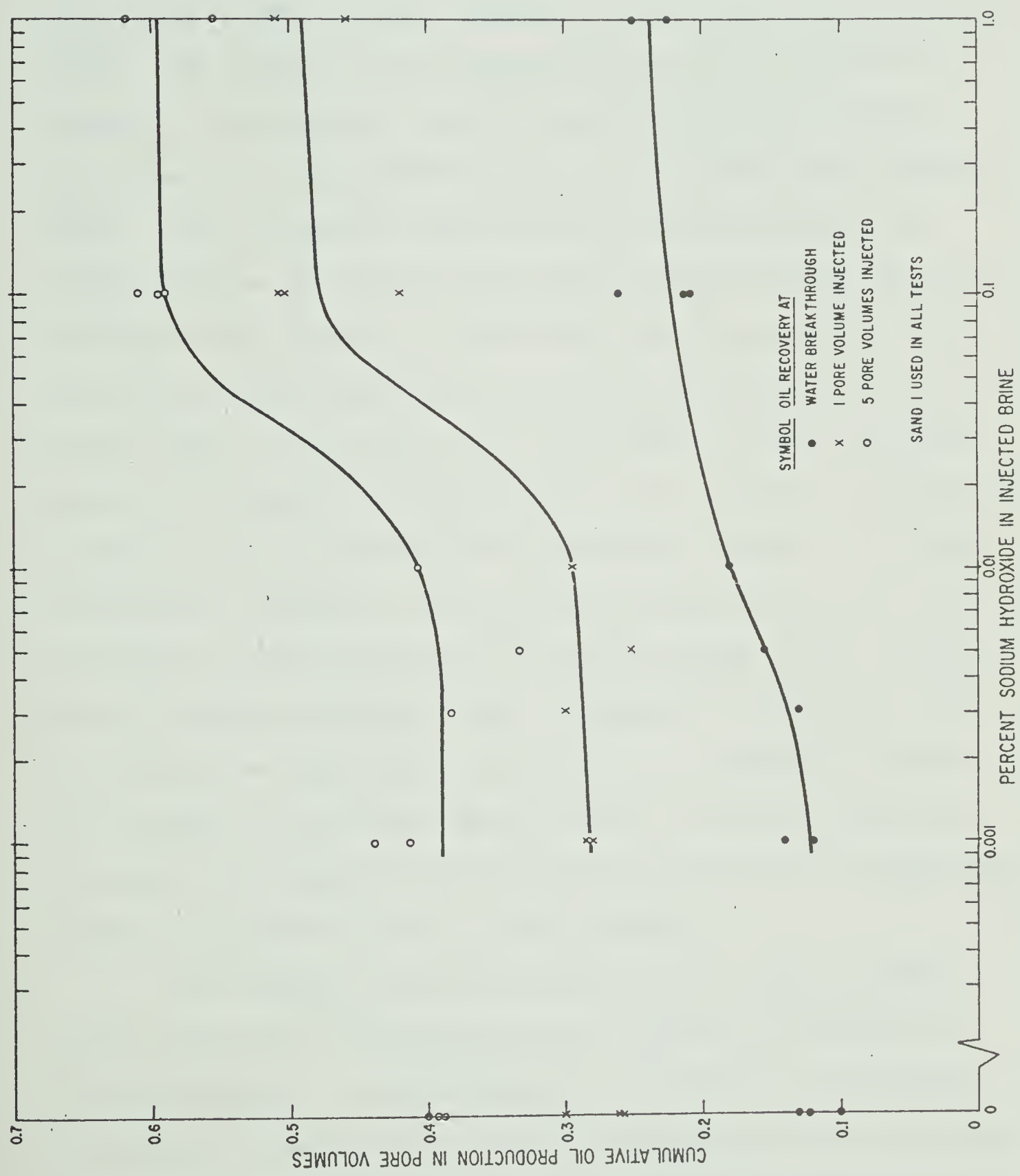


FIG.11- OIL RECOVERY AS A FUNCTION OF SODIUM HYDROXIDE CONCENTRATION IN INJECTED BRINE

a significant increase in oil recovery was realized by the addition of sodium hydroxide to the injected brine.

In addition to the compound sodium hydroxide, displacement tests using a number of other chemicals in the injected brine were conducted. The results of these displacements tests are illustrated in Figure 12. Two chemicals, potassium hydroxide and sodium EDTA were very effective in increasing the recovery of oil from cores containing Sand 1. Three chemicals, sodium carbonate, sodium hydroxide, and sodium phosphate were somewhat less effective than potassium hydroxide and sodium EDTA, however, oil recoveries using these chemicals in the injected brine were significantly increased as compared to the oil recovery during the brine base flood. The addition of sodium metaphosphate to the injected brine resulted in an oil recovery less than that obtained in the base flood at five pore volumes injected. It is significant that interfacial tensions between Lloydminster crude oil and solutions of sodium metaphosphate in brine increased as the concentration of chemical increased. This is demonstrated in Figure B-8. The oil recovery was significantly increased by the addition of chemicals that reduced the interfacial tension between the crude oil and brine solutions. This suggests that interfacial tension may be a significant factor in the recovery of oil by brine flooding.

Two chemicals, sodium tripolyphosphate and sodium pyrophosphate, when added to the injected brine, resulted in an unusual oil recovery response. For these chemicals, oil recovery at breakthrough was similar to that for the base flood. However, oil production during the period of subordinate production was significantly higher than for

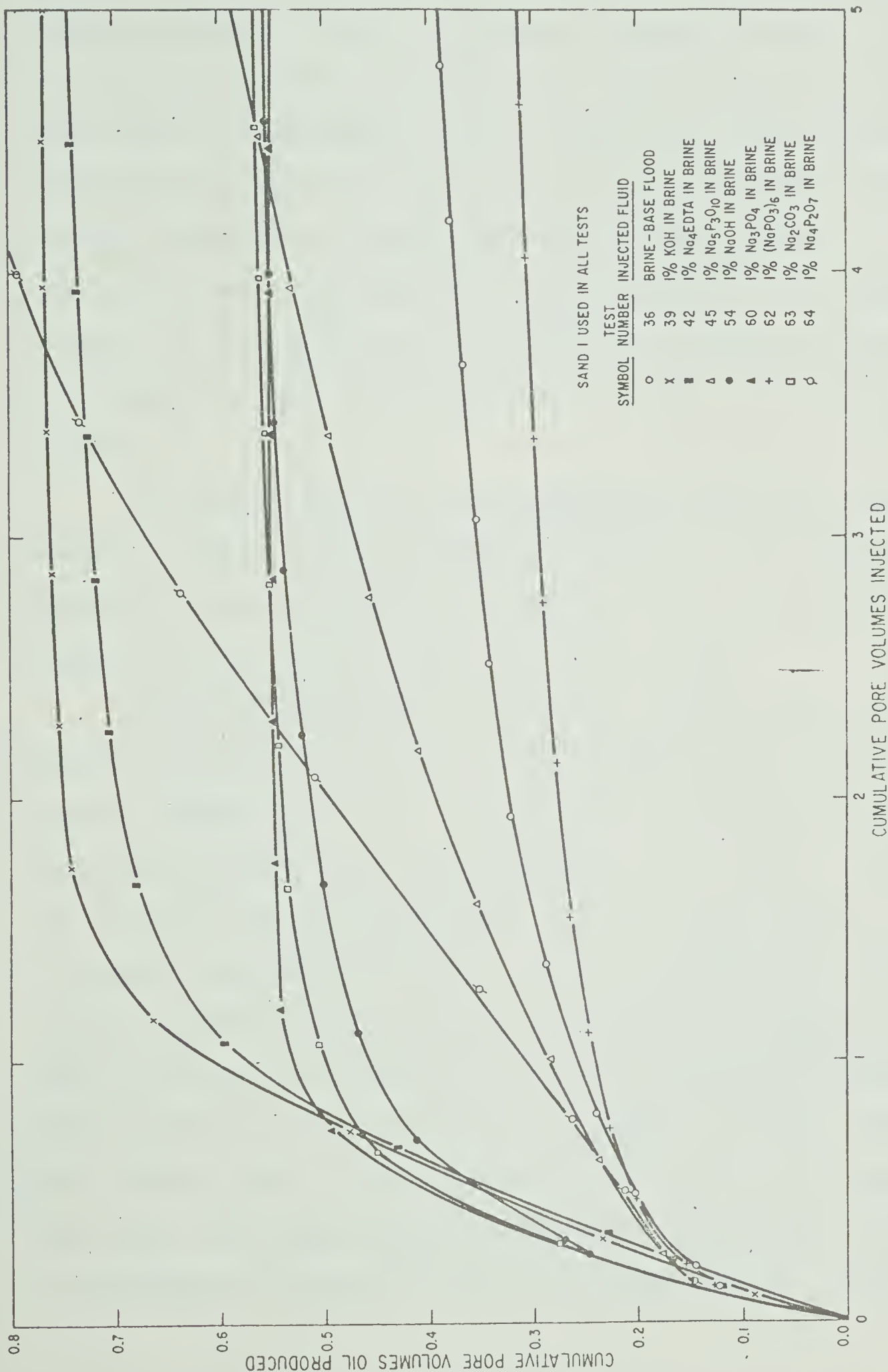


FIG.12 - OIL RECOVERY OF CHEMICAL IN BRINE SOLUTION DISPLACEMENT TESTS - SAND I

the base flood. While both chemicals reduced the interfacial tension between Lloydminster crude oil and brine to a degree as shown in Figure B-8, they were not nearly as effective as a number of other chemicals which reduced the interfacial tension to essentially zero at chemical concentrations well below 1.0 per cent, the concentration used during flooding. Therefore, the beneficial effect of those chemicals on oil recovery may result from wettability changes within the core during flooding. It would appear that the increased oil recovery at breakthrough may be a result of extremely low interfacial tension during flooding.

The pressure behavior during displacement tests with various chemicals in brine is shown in Figure 13. Similar to tests with sodium hydroxide in the injected brine, the highest oil recovery correlates directly with high pressure drop ratios during testing.

Figure 14 illustrates the oil recovery resulting from displacement tests using Sand 3 which contained substantially more clay and fine particles than Sand 1. For test 35, the brine base flood, breakthrough recovery was 0.03 pore volumes of oil. However, subordinate production was significant and at five pore volumes injected, the oil recovery was 0.580 pore volumes. Test 38, in which a 1 per cent solution of potassium hydroxide was injected into a core containing Sand 3, indicated no increase in oil recovery. Potassium hydroxide, which appeared to be very effective in increasing oil recovery from Sand 1, had no effect on oil recovery from Sand 3. Two of the chemicals tested, sodium hydroxide and sodium EDTA, increased both recovery at breakthrough and recovery at five pore volumes injected. An addi-

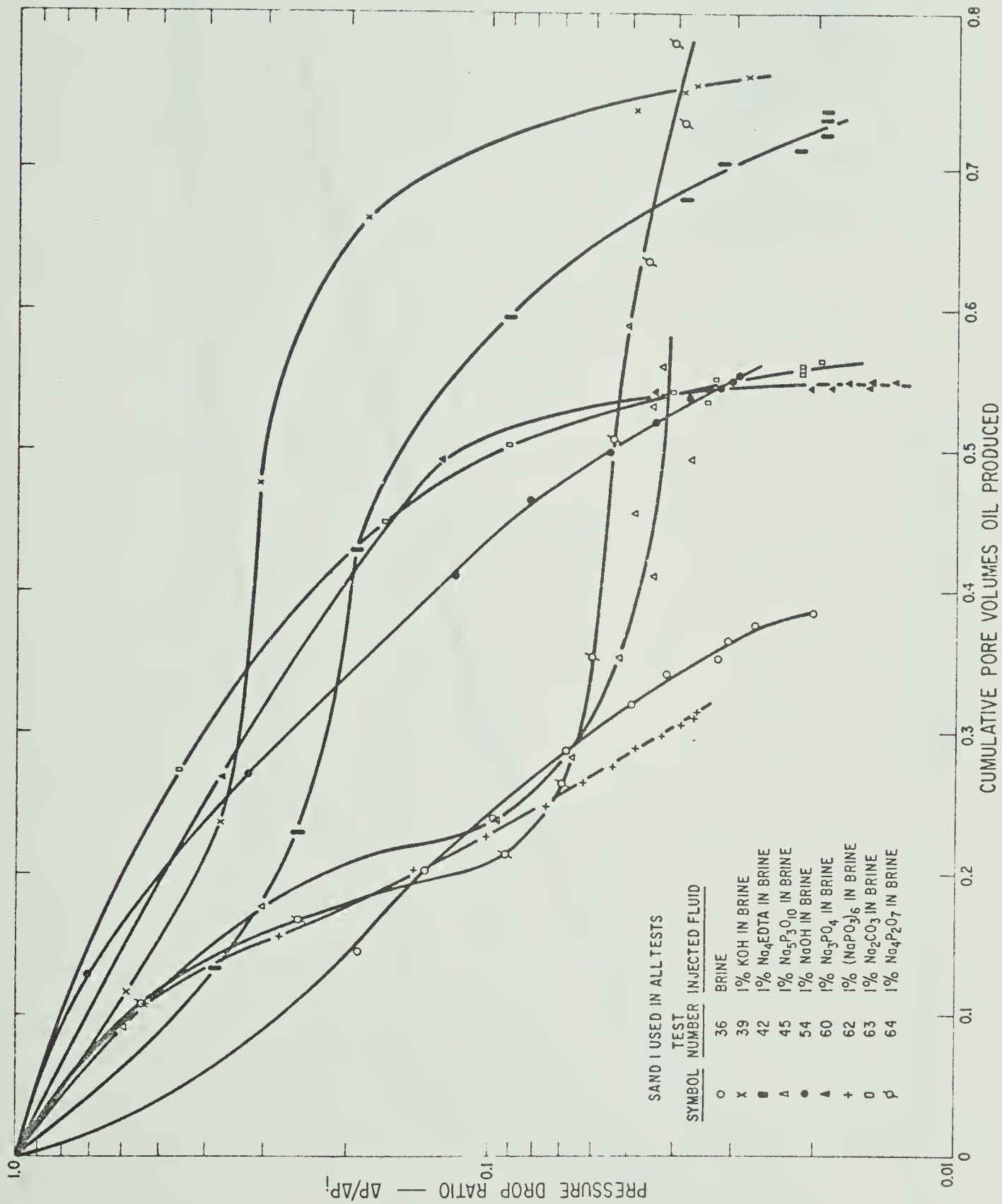


FIG.13 - PRESSURE BEHAVIOUR FOR CHEMICAL IN BRINE SOLUTION DISPLACEMENT TESTS — SAND I

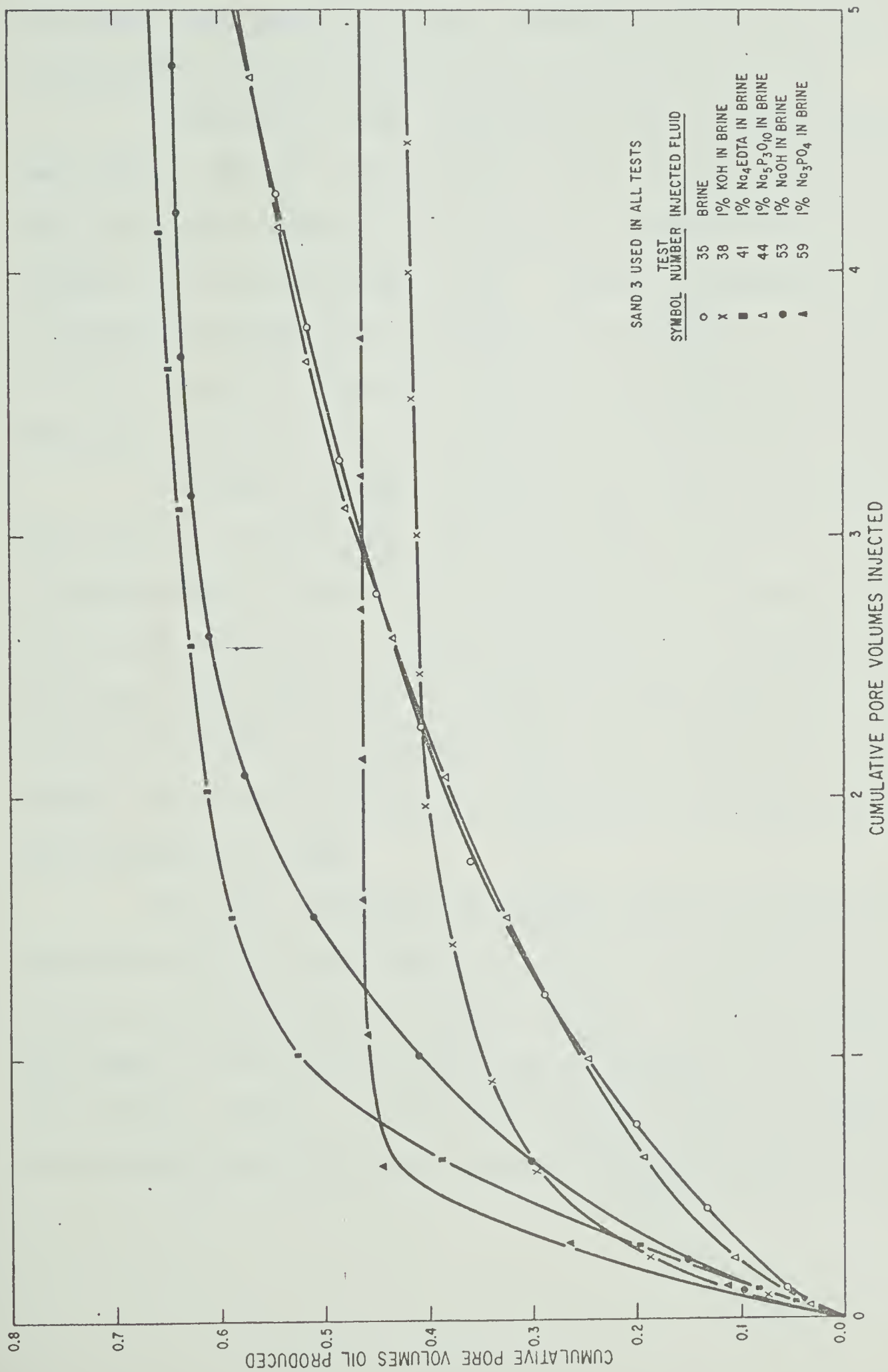


FIG.14-EFFECT OF VARIOUS CHEMICALS ON OIL RECOVERY IN BRINE SOLUTION DISPLACEMENT TESTS — SAND 3

tional two chemicals, sodium tripolyphosphate and sodium phosphate increased breakthrough recovery but recoveries at five pore volumes injected were substantially less than for the brine base case.

A comparison of oil recoveries for brine solution displacement tests on different sands is illustrated in Figure 15. The time of oil and water saturation did not appear to change the recovery performance of tests using Sands 1 and 2. However, a significant change in recovery performance was noted for tests using Sand 3. A comparison of the oil recoveries resulting from the tests indicated that the recovery was decreased as the time of water and oil saturation increased.

Following a conventional brine flood of 4.51 pore volumes, the core used in displacement test 9 was flooded with 0.1 per cent sodium hydroxide in brine solution. No additional oil was recovered and the pressure drop was unchanged from that at the termination of the brine flood. While only one test was run using chemicals in the injected fluid after a conventional brine flood, the limited results suggest that chemical flooding of a previously brine flooded core may not increase oil recovery.

The cores prepared for displacement tests 65, 66 and 67 were saturated with field water instead of brine and then flooded with a 0.1 per cent sodium hydroxide in brine solution. A white precipitate was evident in the produced fluids after approximately one pore volume was injected. However, the precipitate did not cause core plugging as the pressure drop across the cores did not change during the tests.

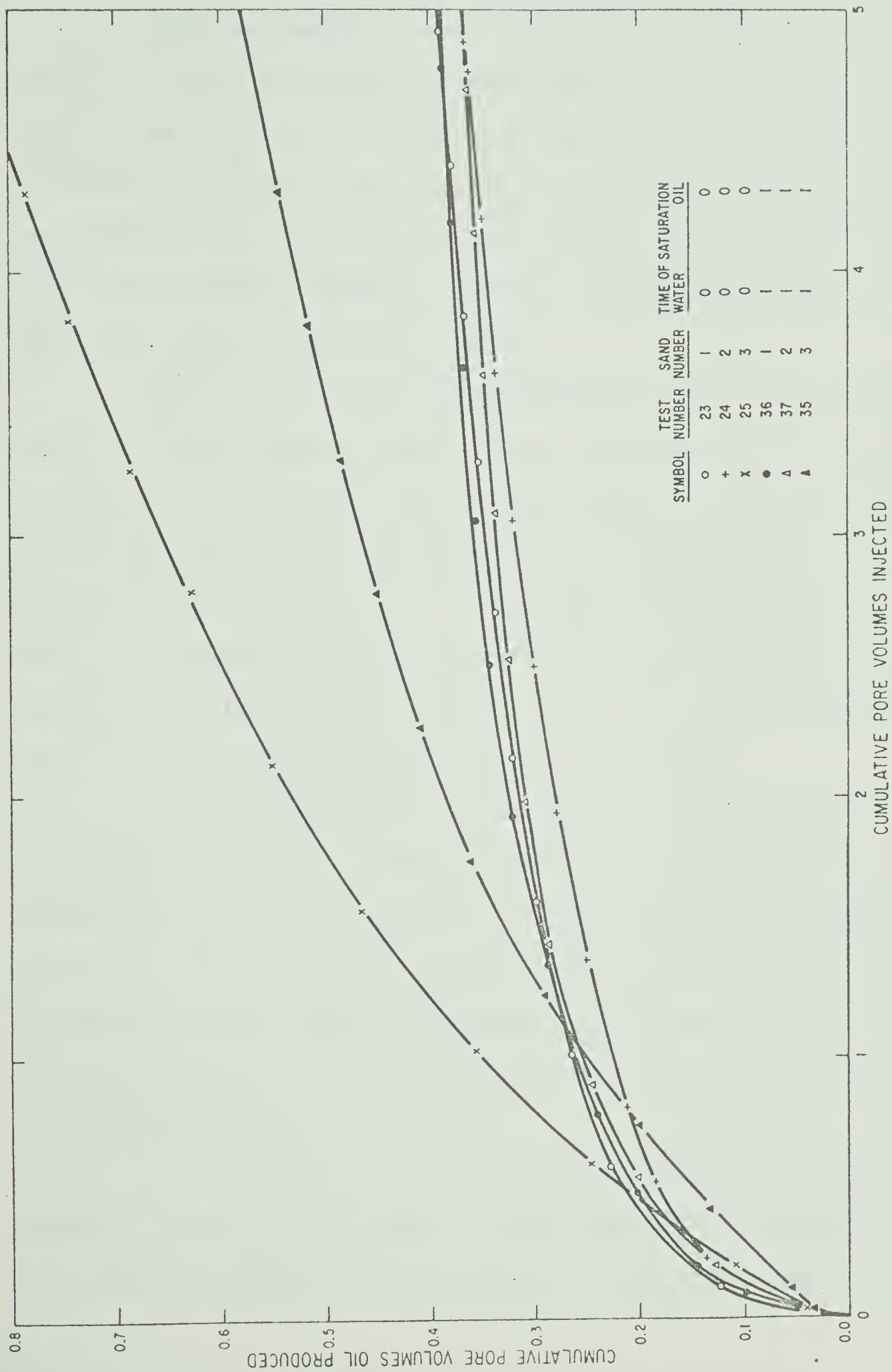


FIG.15 - COMPARISON OF OIL RECOVERY FOR BRINE SOLUTION DISPLACEMENT TESTS ON DIFFERENT SANDS

DISCUSSION

Bench and imbibition test results indicate that the Sparky sands, as cleaned and prepared, were preferentially oil wet. Both types of tests are qualitative in that they do not indicate the degree of wetting. The bench tests are simple and quick and require a minimum amount of sand for testing. This type of test could be used in screening a large number of chemical solutions to determine which chemicals might alter the wettability of a sand.

Both types of tests also indicated that the wetting characteristics of Ottawa sand were changed by some components in the crude oil. Therefore, a core sand that was initially water-wet could be changed to oil-wet by exposing it to the crude oil for a period of time. The wettability characteristics of the sand, assuming they were not changed during the recovery or cleaning process, could then be expected to be oil-wet as a result of contact with the crude. The oil-wet nature of the test sand was substantiated by means of such tests.

The interfacial tension data indicate that a substantial reduction in the amount of chemical required to reduce interfacial tension is realized by the presence of sodium chloride in the aqueous solution. This may have some practical value in that the cost of an injection fluid with desired interfacial tension properties may be reduced if a combination of simple chemicals can be utilized rather than a single, more expensive one.

The interfacial tension results indicate that a substantial amount of chemical may be needed if the injected fluid becomes diluted with reservoir waters containing calcium and magnesium. These alkaline

earths react with basic solutions reducing the pH of the solution. The presence of the hydroxyl ions in the displacing fluid appears necessary in order to reduce the interfacial tension. For example, measurements of pH indicate that the lowest interfacial tension values were obtained at the highest pH.

The interfacial tensions for Varsol and iso-octane were unaffected by sodium hydroxide in solution. If increased oil recovery is dependent upon the reduction of interfacial tension, then other crude oils may not benefit from chemicals in solution if the interfacial tension is not reduced.

Interfacial tension between Lloydminster crude and sodium hydroxide solutions is not a direct function of the solution pH as is illustrated in Figure 6. Furthermore, Figures 8 and 11 show that no significant change in oil recovery was apparent until the sodium hydroxide concentration in the injected fluid exceeded 0.01 per cent even though the interfacial tension was reduced to a value less than 0.4 dynes per centimeter at a concentration of 0.005 per cent. Undoubtedly the sodium hydroxide concentration in the injected fluid would be decreased by the water within the core. Possibly sodium hydroxide would react at contacted sand surfaces and oil-water interfaces, thus depleting the injection fluid of sodium hydroxide. Therefore, the leading edge of the injected fluid may have been depleted of sodium hydroxide to the point that the interfacial tension was not sufficiently reduced to influence recovery. The flood could then be expected to behave like a brine flood.

With high sodium hydroxide concentrations in the injected fluid, sufficient chemical would always be present at the leading edge

to reduce interfacial tension. The maximum benefit appears to have been realized at the point where the concentration at the leading edge is just sufficient to reduce interfacial tension. No increase in recovery was observed as the sodium hydroxide concentration was increased above 0.1 per cent.

During displacement tests conducted with high concentrations of sodium hydroxide the fluid produced after breakthrough was observed to be a very stable water-in-oil emulsion. It would appear that the emulsion was created within the core. In fact, one may explain the emulsion formation and oil displacement in the following manner. The interfacial tension between the injected water and the crude should have been very low due to the high sodium hydroxide concentration in the water. As water invaded the oil-wet core, it would flow along the path of least resistance, undoubtedly the larger pore spaces. However, because of the low interfacial tension, the water could become dispersed in the form of droplets throughout the oil. Due to possible interfacial film formation or depletion of the sodium hydroxide within the droplet, it would not easily deform when it reached a pore restriction. Thus, the flow of water would, at least temporarily, be blocked in a flow path that previously had little resistance to the flow of water. The water would then be forced to follow the next path of least resistance until emulsification took place and the path was, in turn, temporarily blocked. The emulsified water would only move when all other paths of lesser resistance were blocked. Emulsification would continue until the emulsion moved as a front or slug. Due to its low mobility, the emulsion could very efficiently displace oil. Water could not channel through either

the oil or the emulsion without emulsifying and adding to the emulsion slug size.

It will be recalled that the pressure drop ratio during the most successful floods did not fall as rapidly during the first pore volume of injection as is illustrated in Figure 10. The increased resistance to flow in the core suggests that the mobility of water was reduced. The pressure drop ratio was sustained until after the first pore volume of injection, then it decreased rapidly in a fashion similar to the base flood. This type of action is what might be expected if in situ emulsion formation occurred. Furthermore, at one pore volume of injection, an emulsified slug, if it indeed were formed, would have been nearly completely displaced, therefore, the water mobility would increase and the pressure drop ratio would decrease as was observed in Figure 10.

Figures 9 and 13 show that, regardless of the chemical added to the injected fluid, the most efficient floods were those in which the pressure drop was sustained during the test.

As a result of this investigation, a number of chemicals in a brine solution were found to increase the recovery of a high viscosity crude oil by water flooding. From the displacement test results, it would seem that the increased recovery at breakthrough correlates with the reduction to essentially zero of the interfacial tension between the Lloydminster crude oil and the injected water. Displacement tests using chemicals that did not reduce the interfacial tension to an extremely low value resulted in breakthrough recoveries similar to those of the brine base flood.

The behavior of two unusual floods, tests 45 and 64, is shown in Figure 12. The interfacial tension between the crude and injected fluid was reduced somewhat but was appreciably different from zero. Breakthrough recoveries were similar to the base floods but the oil production rate after breakthrough increased significantly. At five pore volumes of injection, oil recoveries were significantly higher than the base flood. It may be noted that as in the other cases, the pressure ratio levelled off as is evident from Figure 13. The delayed response shown by these two floods may have resulted from either the delayed formation of an in situ emulsion or slow core wettability reversal.

Tests using Sand 3 show that some chemicals, namely KOH, $\text{Na}_5\text{P}_3\text{O}_{10}$ and Na_3PO_4 , were not as effective in displacing oil as they were in Sand 1. The higher fraction of clays and fine sands in Sand 3 may have reduced the effectiveness of the chemicals. The clays may have reacted with or adsorbed the chemicals in the injected fluid, thereby reducing the effectiveness of the fluid as a displacing agent.

Another explanation for the decreased oil recovery may be that the cores containing Sand 3 may not have reached wettability equilibrium and wettability conditions may have differed between cores. As shown in Figure 15, oil recovery decreased as the time of water and oil saturation increased, indicating that the sand may have become more oil-wet as the time of oil saturation increased. The inconsistent recovery illustrated in Figure C-3 is possibly a result of variable wettability conditions at the beginning of the displacement tests.

CONCLUSIONS

As a result of this experimental investigation into the effects of chemicals on the recovery of viscous crude oil by water flooding, the following conclusions may be made:

1. The Sparky sand samples used were preferentially oil-wet.
2. The Lloydminster crude oil employed in the study apparently contained constituents which changed the wettability characteristics of a normally preferentially water-wet Ottawa sand to preferentially oil-wet.
3. The presence of sodium chloride in aqueous solutions reduced the amount of chemicals such as sodium hydroxide, potassium hydroxide, sodium carbonate, sodium phosphate, and sodium (tetra) ethylenediamine tetraacetate required to reduce the interfacial tension between Lloydminster crude oil and the aqueous solutions to a given level.
4. With the exception of sodium (tetra) ethylenediamine tetraacetate, a precipitate formed when chemicals were added to a field water sample from the Lloydminster area.
5. The precipitates formed by the addition of chemicals to field water were likely insoluble hydroxides of calcium and magnesium.
6. The interfacial tension and pH behavior of a field water was simulated by means of a complex salt solution reconstructed in the laboratory.

7. Large amounts of chemicals were required to reduce the interfacial tension between Lloydminster crude and field water.
8. The injection of a one per cent sodium hydroxide in brine solution into a Sparky sand core did not cause any apparent plugging of the core.
9. Lloydminster crude oil emulsifies readily with various aqueous solutions. The resulting emulsions were very stable when the interfacial tension between the oil and the aqueous solution was low.
10. Sodium hydroxide concentrations less than 0.01 per cent in brine had little effect on recovery as compared to brine floods.
11. Sodium hydroxide concentrations greater than 0.1 per cent in brine increased recovery at breakthrough by 100 per cent and at five pore volumes injected by 50 per cent.
12. Oil recovery was unchanged as the sodium hydroxide concentration exceeded 0.1 per cent.
13. A number of chemicals in brine increased oil recoveries as compared to brine floods. The chemicals that improved recoveries were sodium hydroxide, potassium hydroxide, sodium carbonate, sodium (tetra) ethylenediamine tetraacetate, sodium phosphate, sodium tripolyphosphate and sodium pyrophosphate.

RECOMMENDATIONS

The influence of a number of chemicals on oil recovery was investigated during this study. Additional investigation is necessary to determine if other chemicals can be found which will further improve oil recovery. Further study of some of the chemicals used in this investigation should be conducted so as to determine the concentrations required for optimum recovery to be realized.

The effect of sodium chloride on interfacial behavior should be more fully investigated. Other chemicals, as well, should be tested.

The results of this study indicate that the amount of chemical required to reduce interfacial tension is reduced by the presence of common and inexpensive salt in the solution. Further experimental study would be necessary to determine optimum combinations of chemicals that should be used.

The production of a stable emulsion during displacement tests has been observed during this and previous studies. A survey of the literature indicates that the injection of micro-emulsions may greatly enhance recoveries. Therefore, a study of the effect of emulsions on recovery should be initiated. Prepared emulsions could be injected into sand cores to ascertain whether or not increased recoveries could be obtained in viscous crude oil reservoirs. Inherent in the production of emulsions is the problem of de-emulsification. Artificially created emulsions may prove difficult to break as were the emulsions produced during this study. If a study of emulsion injection is initiated, a related study on emulsion breaking should also be considered.

Further tests should be conducted to establish if chemical solution flooding of previously flooded-out cores will increase oil recovery.

The results of this research project should eventually be followed by field trials and testing. Consideration might be given to studying the economics of chemical flooding. In addition to optimum chemical concentrations, optimum injection slug sizes should be considered.

LIST OF SYMBOLS

API	-	American Petroleum Institute
ASTM	-	American Society for Testing Materials
At	-	adhesion tension
C	-	viscous fingering scaling constant
cc	-	cubic centimeter
cm	-	centimeter
cp	-	centipoise
$^{\circ}\text{F}$	-	Fahrenheit degrees
fw	-	fraction water flowing
gm	-	gram
h	-	lateral core dimension
hr	-	hour
IOIP	-	initial oil-in-place
K	-	absolute permeability
ko	-	relative permeability to oil
kw	-	relative permeability to water
L	-	length
ml	-	millilitre
Np	-	oil produced
ΔN_p	-	incremental oil produced
PV	-	pore volume
Pc	-	capillary pressure
Po	-	pressure in oil phase
Pw	-	pressure in water phase

- ΔP - pressure drop
- ΔP_i - initial pressure drop
- q_t - total flow rate per unit area
- r - radius
- V - total flow rate per unit area
- W_i - water injected
- X - horizontal distance
- μ_o - oil viscosity
- μ_w - water viscosity
- θ - contact angle
- λ_{cr} - critical finger distance
- τ_{so} - interfacial tension between solid and oil
- τ_{sw} - interfacial tension between solid and water
- τ_{wo} - interfacial tension between water and oil

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APPENDIX A

SAND AND FLUID PROPERTIES

TABLE A-1Code for Sand Identification

<u>Sand Number</u>	<u>Sand Identification</u>
1	Sparky sand from well Fargo Husky Lone Rock A-7-9-47-27 W3M cleaned with hot water and Varsol. Oven dried at 250° F for 8 hours.
2	Sparky sand from same well cleaned with toluene. Oven dried at 250° F for 8 hours.
3	Sparky sand from same well cleaned with Varsol and air dried at room temperature.
4	Similar to Sand 3 except sand contains a higher percentage of fine sand and clay.
5	Ottawa sand cleaned with hot water and oven dried at 250° F for 8 hours. Water wet sand 20-40 U.S. mesh in size.
6	Sparky sand from Cold Lake area. Hermetically sealed, uncleaned, unconsolidated sand from rubber sleeved core barrel.

TABLE A-2

Sieve Analysis of Core SandsSparky Sand - Fargo Husky Lone Rock A-7-9-47-27 W3M

<u>Mesh</u> <u>U.S. Series</u>	<u>Sieve Opening</u>		<u>Weight Percent Retained</u>			
	<u>Inches</u>	<u>Millimeters</u>	<u>Sand 1</u>	<u>Sand 2</u>	<u>Sand 3</u>	<u>Sand 4</u>
40	0.0165	0.42	0	0	0	0
60	0.0098	0.250	4.10	5.67	2.02	2.13
80	0.0070	0.177	41.62	55.93	55.39	12.63
100	0.0059	0.149	23.86	11.75	3.71	20.08
120	0.0049	0.124	13.74	11.41	11.44	22.31
200	0.0029	0.074	14.12	10.31	16.99	32.68
325	0.0017	0.044	2.42	3.48	7.08	7.69
-325	∠0.0017	∠0.044	0.14	1.45	3.37	2.48

<u>Mesh</u> <u>U.S. Series</u>	<u>Cumulative Percent of Sand Passing Through Sieves</u>			
	<u>Sand 1</u>	<u>Sand 2</u>	<u>Sand 3</u>	<u>Sand 4</u>
40	100.00	100.00	100.00	100.00
60	95.90	94.33	97.98	97.87
80	54.28	38.60	42.59	85.24
100	30.42	26.65	38.88	65.16
120	16.68	15.24	27.44	42.85
200	2.56	4.93	10.45	10.17
325	0.14	1.45	3.37	2.48

<u>Mesh</u> <u>U.S. Series</u>	<u>Cumulative Percent of Sand Retained by Sieves</u>			
	<u>Sand 1</u>	<u>Sand 2</u>	<u>Sand 3</u>	<u>Sand 4</u>
40	0.00	0.00	0.00	0.00
60	4.10	5.67	2.02	2.13
80	45.72	61.60	57.41	14.76
100	69.58	73.35	61.12	34.84
120	83.32	84.76	72.56	57.15
200	97.44	95.04	89.55	89.83
325	99.86	98.55	96.63	97.52
-325	100.00	100.00	100.00	100.00

TABLE A-3Crude Oil Properties

Crude A - Lloydminster crude oil with water removed at separator

Crude B - Maidstone crude oil from lease tank of well Husky Maidstone
A-1-11-48-23 W3M

<u>Crude</u>	<u>API Gravity</u> <u>°API</u>	<u>Density</u> <u>gm/cc</u>	<u>Basic Sediment and Water</u> <u>% By Volume</u>
A	17.0	0.953	0.1
B	13.7	0.974	7.5

Viscosity Measurements - Brookfield Rotating Viscometer

<u>Crude</u>	<u>Time of Agitation</u> <u>Minutes</u>	<u>Viscosity</u> <u>cp</u>
A	0	1312
A	15	1205
A	30	1157
B	0	5845
B	15	5827

Viscosity Measurements - Bendix Lab - Vis Viscometer

<u>Crude</u>	<u>Temperature</u> <u>°F</u>	<u>Meter Reading</u>	<u>Density</u> <u>gm/cc</u>	<u>Viscosity</u> <u>cp</u>
A	78	940	0.953	986
A	80	915	0.953	940

Viscosity of Varsol, Iso-octane and Crude Oil Mixtures -
Bendix Lab - Vis Viscometer

<u>Oil</u>	<u>API Gravity</u> <u>°API</u>	<u>Density</u> <u>gm/cc</u>	<u>Meter Reading</u>	<u>Viscosity</u> <u>cp</u>	<u>Mixture</u> <u>Ratio</u>
Varsol	48.5	0.796	0.33	0.414	-
Varsol - Crude A	42.3	0.815	0.88	1.080	6:1
Iso-octane	71.7	0.697	0.10	0.144	-
*Iso-octane - Crude A	60.3	0.739	0.35	0.414	6:1

*Iso-octane - Crude A mixture left wax or paraffin deposit on wall of glass container.

TABLE A-4Properties of Brine, Complex Salt Solution
and Field Waters

Brine	-	Prepared solution of 84.84 grams NaCl per litre of solution.												
		Density - 1.056 gm/cc at 80° F												
		Viscosity - 0.993 centipoise at 80° F												
Complex Salt Solution	-	Prepared solution of chemicals intended to simulate field water from well 2-24-50-2 W4M in Lloydminster area. Chemical content of complex salt solution is as follows:												
		<table><tr><td><u>Chemical</u></td><td><u>Amount in Solution</u> <u>gms/litre</u></td></tr><tr><td>CaCl₂</td><td>13.55</td></tr><tr><td>MgCl₂</td><td>9.25</td></tr><tr><td>NaBr</td><td>0.330</td></tr><tr><td>NaHCO₃</td><td>0.302</td></tr><tr><td>NaCl</td><td>67.20</td></tr></table>	<u>Chemical</u>	<u>Amount in Solution</u> <u>gms/litre</u>	CaCl ₂	13.55	MgCl ₂	9.25	NaBr	0.330	NaHCO ₃	0.302	NaCl	67.20
<u>Chemical</u>	<u>Amount in Solution</u> <u>gms/litre</u>													
CaCl ₂	13.55													
MgCl ₂	9.25													
NaBr	0.330													
NaHCO ₃	0.302													
NaCl	67.20													
		Density - 1.060 gm/cc at 77° F												
Field Water	-	From Devon Palmer Battery No.1, Chauvin, Alberta												
		Density - 1.0589 gm/cc at 60° F												
Field Water Sample 2	-	From well Devon Palmer Chauvin 8-28-43-1 W4M												
		Density - 1.0600 gm/cc at 60° F												

TABLE A-5

Comparison of Chemical Analyses of Complex Salt Solution
and Field Waters

<u>Sample</u>	<u>Solids Content Milligrams/Litre</u>			
	<u>2-24-50-2 W4</u>	<u>Complex Salt Solution</u>	<u>Field Water</u>	<u>Field Water Sample 2</u>
Chloride	56,411	56,330	53,114	53,168
Bromine	256	256	191	194
Iodide	11	0	12	11
Carbonate	0	0	0	0
Bicarbonate	219	219	95	462
Hydroxide	0	0	0	0
Sulphate	2	0	8	5
Calcium	4,990	4,890	2,494	2,630
Magnesium	2,359	2,359	1,147	1,117
Sodium (Calculated*)	26,578	26,578	31,468	29,587
Total Solids (Calculated)	90,856	90,632	88,529	87,174
Total Solids (After Ignition)	98,460		83,390	84,870
Density (60° F)	1.0632	1.061	1.0589	1.0600
pH	6.4	7.06	7.20	7.16

* . Alkali metals calculated as Sodium

TABLE A-6Identification of Chemicals Tested

<u>Chemical Name</u>	<u>Chemical Formula</u>
Sodium Hydroxide	NaOH
Sodium Carbonate	Na ₂ CO ₃
Sodium Metaphosphate	(Na PO ₃) ₆
Sodium Phosphate - Tribasic	Na ₃ PO ₄ . 12 H ₂ O
Sodium Phosphate - Tripoly	Na ₅ P ₃ O ₁₀
Sodium Pyrophosphate	Na ₄ P ₂ O ₇
Sodium (Tetra) Ethylenediamine Tetraacetate	Na ₄ EDTA or N-CH ₂ -CH ₂ -N (CH ₂ (COONa) ₄)
Potassium Hydroxide	KOH

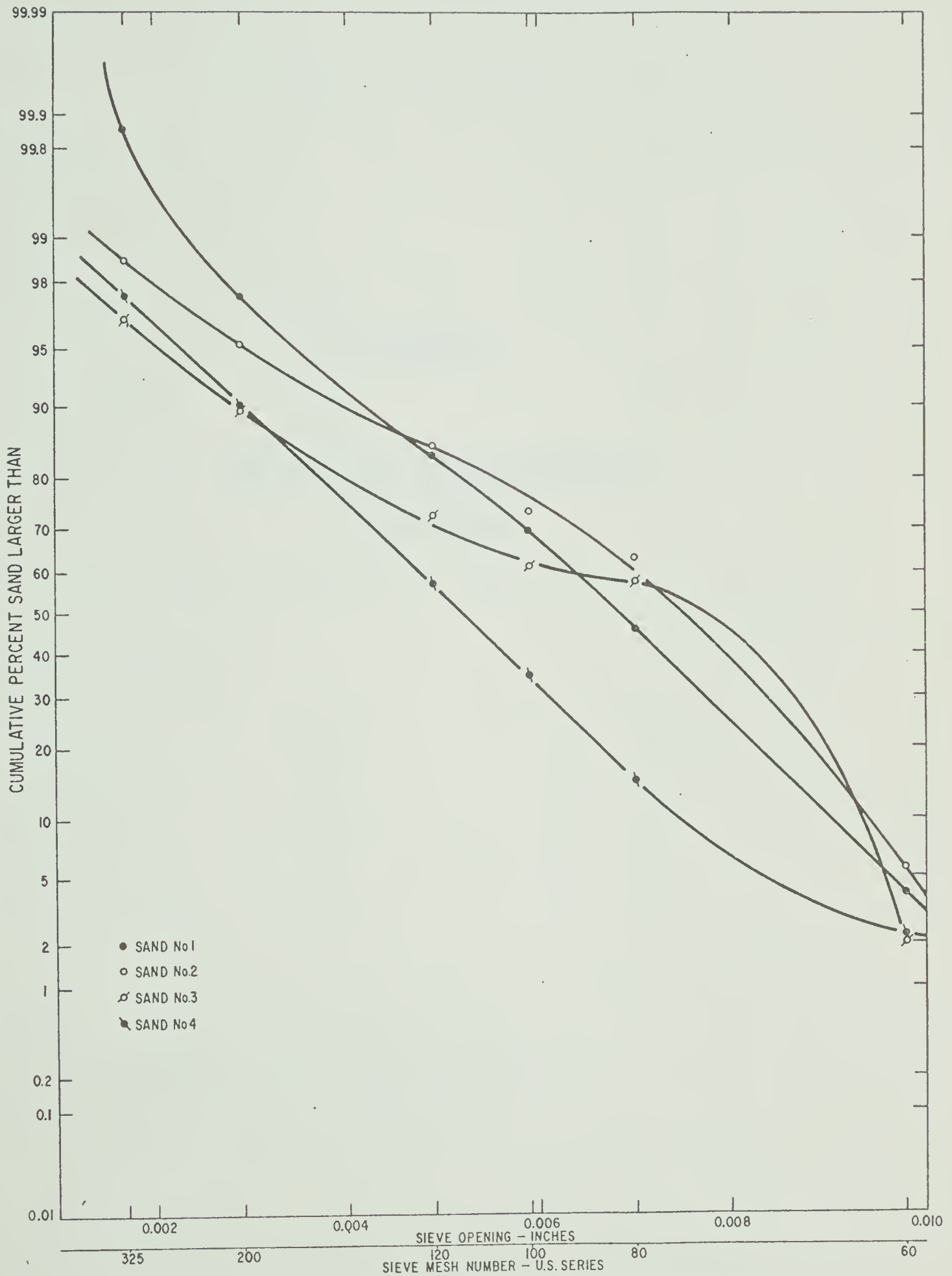


FIG. A-1 - FREQUENCY DISTRIBUTION OF SPARKY SANDS

APPENDIX B

IMBIBITION AND INTERFACIAL TENSION

TEST RESULTS

TABLE B-1Bench Test Imbibition ResultsImbibition of Fluids into Dry Sands

<u>Imbibing Fluid</u>	<u>Sand Number</u>				
	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>
Varsol	SP	SP	SP	SP	SP
Varsol - Crude Mixture	SP	SP	SP	SP	SP
Brine	VSL	SL	N	N	SP
0.5% NaOH - Brine	SL	SL	N	N	SP
0.5% Na ₂ CO ₃ - Brine	SL	SL	N	N	SP
0.5% KOH - Brine	SL	SL	N	N	SP
0.5% Na ₄ EDTA - Brine	SL	SL	N	N	SP
0.5% Na ₃ PO ₄ - Brine	SL	SL	N	N	SP
0.1% Na ₄ P ₂ O ₇ - Brine	SL	SL	N	N	SP
0.5% (Na PO ₃) ₆ - Brine	SL	SL	N	N	SP
0.5% Na ₅ P ₃ O ₁₀ - Brine	SL	SL	N	N	SP

Imbibition of Varsol-Crude Mixture into Fluid Saturated Sands

<u>Saturation Fluid</u>	<u>Sand Number</u>				
	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>
Brine	SP	SP	SP	SP	SP
0.5% NaOH - Brine	SP	SP	SP	SP	SP
0.5% Na ₂ CO ₃ - Brine	SP	SP			SP
0.5% KOH - Brine	SP	SP			SP
0.5% Na ₄ EDTA - Brine	SP	SP			SP
0.5% Na ₃ PO ₄ - Brine	SP	SP			SP
0.1% Na ₄ P ₂ O ₇ - Brine	SP	SP			SP
0.5% (Na PO ₃) ₆ - Brine	SP	SP			SP
0.5% Na ₅ P ₃ O ₁₀ - Brine	SP	SP			SP

CODE

SP - Spontaneous imbibition of imbibing fluid
 N - No imbibition of imbibing fluid
 SL - Slow imbibition of imbibing fluid
 VSL - Very slow imbibition of imbibing fluid

TABLE B-1 (continued)Imbibition of Varsol into Brine Saturated Sands

<u>Imbibing Fluid</u>	<u>Sand Number</u>				
	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>
Varsol	SP	SP	SP	SP	SP

Imbibition of Various Fluids into Varsol-Crude Saturated Sands

<u>Imbibing Fluid</u>	<u>Sand Number</u>				
	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>
Brine	N	VSL	N	N	N
0.5% NaOH - Brine	SP	SP	SL	SL	SP
0.5% Na ₂ CO ₃ - Brine	SP	SP	SL	SL	SP
0.5% KOH - Brine	SP	SP	SL	SL	SP
0.5% Na ₄ EDTA - Brine	SL	SP	N	SL	SL
0.5% Na ₃ PO ₄ - Brine	SP	SP	SL	SL	SP
0.1% Na ₄ P ₂ O ₇ - Brine	N	SP	N	N	VSL
0.5% (Na PO ₃) ₆ - Brine	N	VSL	N	N	N
0.5% Na ₅ P ₃ O ₁₀ - Brine	N	VSL	N	N	VSL

Imbibition of Brine into Varsol Saturated Sand

<u>Imbibing Fluid</u>	<u>Sand Number</u>				
	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>
Brine	N	SL	N	N	SP

CODE

- SP - Spontaneous imbibition of imbibing fluid
 N - No imbibition of imbibing fluid
 SL - Slow imbibition of imbibing fluid
 VSL - Very slow imbibition of imbibing fluid

TABLE B-2
Summary of Cell Imbibition Test Data

Test Number and Saturating Fluid	Sand Type	Packed Weight gms	Cell Weight gms	Sand Weight gms	Saturated Weight gms	Fluid Weight gms	Fluid Volume cc	Sand Volume cc	Imbibing Fluid	Cell Porosity %
1	Iso-octane	5	98.27	57.04	41.23	103.90	5.63	8.09	Brine	31.4
2	"	1	91.74	51.78	39.96	99.06	7.32	10.51	"	40.8
3	"	2	93.61	51.86	41.75	101.00	7.39	10.61	"	41.2
4	"	3	89.77	51.88	37.89	98.10	8.33	11.96	"	46.4
5	"	4	89.06	57.09	31.97	97.25	8.19	10.76	"	41.8
6	Varsol	5	99.51	57.11	42.40	105.96	6.45	8.10	"	31.5
7	"	1	94.59	51.80	42.79	102.60	8.01	10.07	"	39.1
8	"	2	93.79	51.86	41.93	102.16	8.37	10.51	"	40.8
9	"	3	90.30	51.93	38.37	99.78	9.48	11.91	"	46.3
10	"	4	89.33	57.10	32.23	99.08	9.75	12.24	"	47.6
11	Brine	5	99.39	57.22	42.17	108.48	9.09	8.59	Varsol	33.4
12	"	1	94.44	51.81	42.53	106.08	11.64	11.01	"	42.7
13	"	2	94.45	51.94	42.51	105.80	11.35	10.72	"	41.7
14	"	3	90.35	51.88	38.47	103.63	13.28	12.55	"	48.8
15	"	4	89.43	57.12	32.31	101.37	11.94	11.29	"	43.8
16	Crude-Varsol	5	98.23	51.87	46.36	105.70	7.47	9.17	Brine	35.6
17	"	1	94.30	52.04	42.26	103.24	8.94	10.97	"	42.6
18	"	3	89.27	52.07	37.20	98.79	9.52	11.69	"	45.4
19	"	5	99.84	57.18	42.66	106.41	6.57	8.07	1% NaOH - Brine	31.3
20	"	1	95.58	51.94	43.64	104.17	8.59	10.54	"	41.0
21	"	3	90.39	52.01	38.38	100.42	10.03	12.31	"	47.8
22	"	5	95.29	52.05	43.25	102.68	7.39	9.06	1% Na5 P3 O10 - Brine	36.2

Cell Volume = 25.75 cc

TABLE B-3Summary of Results of Cell Imbibition Tests

<u>Imbibition Time Hours</u>	<u>Imbibed Volume cc</u>	<u>Pore Volume Imbibed %</u>	<u>Imbibition Time Hours</u>	<u>Imbibed Volume cc</u>	<u>Pore Volume Imbibed %</u>
<u>TEST #1</u>			<u>TEST #8</u>		
0.5	0.2	2.5	18.0	0.0	0.0
1.5	0.6	7.4	<u>TEST #9</u>		
2.5	1.0	12.4	12.0	0.0	0.0
4.5	1.7	21.0	<u>TEST #10</u>		
5.5	2.4	29.7	13.5	0.0	0.0
23.5	3.8	47.0	<u>TEST #11</u>		
28.5	4.2	51.9	3.5	0.3	3.5
30.5	4.3	53.1	19.25	0.4	4.7
70.0	5.3	65.5	<u>TEST #12</u>		
<u>TEST #2</u>			4.25	0.3	2.7
10.5	0.1	1.0	24.0	0.3	2.7
24.0	0.1	1.0	<u>TEST #13</u>		
<u>TEST #3</u>			23.25	0.0	0.0
10.5	0.1	0.9	<u>TEST #14</u>		
12.0	0.1	0.9	5.0	0.2	1.6
<u>TEST #4</u>			24.0	0.7	5.6
12.0	0.1	0.8	26.0	0.7	5.6
22.25	0.1	0.8	<u>TEST #15</u>		
<u>TEST #5</u>			10.0	0.4	3.5
12.25	0.1	0.9	11.0	0.7	6.2
14.25	0.1	0.9	26.25	1.0	8.9
<u>TEST #6</u>			30.0	1.1	9.8
0.5	0.6	7.4	46.5	1.3	11.5
1.75	1.4	17.3	<u>TEST #16</u>		
19.75	3.7	45.7	23.75	0.1	1.1
24.0	4.1	50.6			
25.75	4.2	51.9			
<u>TEST #7</u>					
20.25	0.0	0.0			

TABLE B-3 (continued)

<u>Imbibition Time Hours</u>	<u>Imbibed Volume cc</u>	<u>Pore Volume Imbibed %</u>
<u>TEST #17</u>		
29.5	0.0	0.0
<u>TEST #18</u>		
25.25	0.0	0.0
<u>TEST #19</u>		
0.0	1.0	12.4
19.25	4.1	50.8
96.25	4.5	55.8
<u>TEST #20</u>		
21.75	0.3	2.8
<u>TEST #21</u>		
28.25	0.2	1.6
<u>TEST #22</u>		
16.75	1.1	12.1
24.5	1.4	15.5
40.75	1.8	19.9

TABLE B-4

Core Holder Description

Core Holder I.D.	-	0.870 inches
	-	2.21 cm
Core Holder Length	-	6.00 inches
	-	15.23 cm
Core Holder Volume	-	58.4 cc

TABLE B-5

Imbibition Cell Description

Imbibition Cell I.D.	-	1.00 inches
	-	2.54 cm
Imbibition Cell Length	-	2.00 inches
	-	5.08 cm
Imbibition Cell Volume	-	25.75 cc

TABLE B-6

pH and Interfacial Tension Data for Solutions of NaOH
in Distilled Water and Lloydminster Crude Oil - RUN 1

NaOH Concentration Weight Percent	pH		Surface Tension		Interfacial Tension		Temperature ° F
	Apparent	Corrected	Apparent Dynes/cm	Corrected Dynes/cm	Apparent Dynes/cm	Corrected Dynes/cm	
0	5.65	5.65	76.5	71.7	22.8	26.7	77
0.0025	10.45	10.45	76.5	71.7	15.1	16.5	77
0.0050	10.50	10.50	76.4	71.6	13.5	14.5	79
0.0075	11.05	11.05	76.4	71.6	11.9	12.7	79
0.0100	11.40	11.40	76.3	71.5	7.0	6.9	79
0.0125	11.45	11.45	76.3	71.5	4.3	4.2	79
0.0150	11.50	11.50	76.0	71.1	2.3	2.1	80
0.02	11.54	11.54	75.7	70.8	1.7	1.5	80
0.03	11.58	11.58	75.5	70.6	<0.4	<0.4	80
0.04	11.61	11.65	75.1	70.2	<0.4	<0.4	80
0.05	11.64	11.68	75.0	70.1	<0.4	<0.4	80
0.06	11.73	11.78	75.3	70.4	<0.4	<0.4	80
0.07	11.80	11.86	75.6	70.7	<0.4	<0.4	80
0.08	11.81	11.88	75.7	70.8	<0.4	<0.4	80
0.09	11.83	11.90	76.0	71.1	<0.4	<0.4	81
0.10	11.86	11.94	76.0	71.1	<0.4	<0.4	81
0.12	11.89	11.98	75.0	70.1	<0.4	<0.4	81
0.14	11.90	11.99	75.6	70.7	<0.4	<0.4	81
0.16	11.93	12.03	75.1	70.2	<0.4	<0.4	81
0.18	11.93	12.03	75.5	70.6	<0.4	<0.4	81
0.20	11.94	12.05	76.0	71.1	<0.4	<0.4	80
0.25	11.95	12.08	74.7	69.7	<0.4	<0.4	83
0.30	11.98	12.13	75.1	70.2	<0.4	<0.4	83
0.45	12.02	12.20	75.7	70.8	<0.4	<0.4	83
0.60	12.00	12.22	75.5	70.6	<0.4	<0.4	83
0.75	11.98	12.23	75.4	70.5	<0.4	<0.4	83
0.90	11.95	12.23	75.2	70.3	<0.4	<0.4	83
1.10	11.86	12.14	75.5	70.6	<0.4	<0.4	83

NOTE: No precipitate formed at any NaOH concentration

TABLE B-7

pH and Interfacial Tension Data for Solutions of NaOH
in Distilled Water and Lloydminster Crude Oil - RUN 2

NaOH Concentration <u>Weight Percent</u>	pH <u>Measured</u>	<u>Interfacial Tension</u>		Temperature <u>° F</u>
		<u>Apparent Dynes/cm</u>	<u>Corrected Dynes/cm</u>	
0	6.90	23.3	27.4	77
0.002	10.20	15.7	17.3	77
0.004	10.63	15.0	16.4	77
0.006	10.76	13.9	15.0	77
0.008	10.95	10.4	10.8	77
0.010	11.12	7.9	8.0	77
0.02	11.53	1.8	1.1	78
0.04	11.80	<0.4	<0.4	78
0.06	11.97	<0.4	<0.4	78
0.08	12.08	<0.4	<0.4	78
0.10	12.15	<0.4	<0.4	78
0.20	12.45	<0.4	<0.4	78
0.40	12.60	<0.4	<0.4	78
0.60	12.74	<0.4	<0.4	78
0.80	12.80	<0.4	<0.4	78
1.00	12.85	<0.4	<0.4	78
2.00	12.94	<0.4	<0.4	78
4.00	13.10	<0.4	<0.4	78
6.00	13.12	<0.4	<0.4	78
8.00	13.12	<0.4	<0.4	78
10.00	13.10	<0.4	<0.4	78

NOTE: No precipitate formed at any NaOH concentration

TABLE B-8

pH and Interfacial Tension Data for NaOH in Solution
of 0.330 gm/litre NaBr and Lloydminster Crude Oil

<u>NaOH</u> <u>Concentration</u> <u>Weight Percent</u>	<u>pH</u> <u>Measured</u>	<u>Interfacial Tension</u>	
		<u>Apparent</u> <u>Dynes/cm</u>	<u>Corrected</u> <u>Dynes/cm</u>
0	6.30	23.5	27.6
0.002	10.00	13.9	16.4
0.004	10.55	10.6	12.1
0.006	10.90	8.9	9.1
0.008	10.98	6.4	6.3
0.01	11.15	4.5	4.3
0.02	11.45	< 0.4	< 0.4
0.04	11.65	< 0.4	< 0.4
0.06	11.90	< 0.4	< 0.4
0.08	11.96	< 0.4	< 0.4
0.10	12.00	< 0.4	< 0.4
0.20	12.27	< 0.4	< 0.4
0.40	12.55	< 0.4	< 0.4
0.60	12.65	< 0.4	< 0.4
0.80	12.80	< 0.4	< 0.4
1.00	12.82	< 0.4	< 0.4
2.00	12.85	< 0.4	< 0.4
4.00	12.81	< 0.4	< 0.4
6.00	12.78	< 0.4	< 0.4
8.00	12.78	< 0.4	< 0.4
10.00	12.80	< 0.4	< 0.4

NOTE: No precipitate formed at any NaOH concentration

Test temperature 74°F throughout test

TABLE B-9

pH and Interfacial Tension Data for NaOH in Solution
of 0.302 gm/litre NaHCO₃ and Lloydminster Crude Oil

NaOH Concentration <u>Weight Percent</u>	pH <u>Measured</u>	<u>Interfacial Tension</u>		Temperature <u>° F</u>
		<u>Apparent</u> <u>Dynes/cm</u>	<u>Corrected</u> <u>Dynes/cm</u>	
0	8.54	21.4	24.8	73
0.002	9.70	14.5	15.8	73
0.004	9.40	16.4	18.2	73
0.006	9.78	15.3	17.5	73
0.008	10.00	14.3	15.5	74
0.01	10.20	13.5	14.5	74
0.02	11.06	3.8	1.3	74
0.04	11.55	∠ 0.4	∠ 0.4	74
0.06	11.85	∠ 0.4	∠ 0.4	74
0.08	12.05	∠ 0.4	∠ 0.4	73
0.10	12.18	∠ 0.4	∠ 0.4	73
0.20	12.40	∠ 0.4	∠ 0.4	73
0.40	12.60	∠ 0.4	∠ 0.4	73
0.60	12.72	∠ 0.4	∠ 0.4	73
0.80	12.81	∠ 0.4	∠ 0.4	73
1.00	12.90	∠ 0.4	∠ 0.4	73
2.00	12.97	∠ 0.4	∠ 0.4	73
4.00	12.96	∠ 0.4	∠ 0.4	73
6.00	12.92	∠ 0.4	∠ 0.4	73
8.00	12.90	∠ 0.4	∠ 0.4	73
10.00	12.76	∠ 0.4	∠ 0.4	73

NOTE: No precipitate formed at any NaOH concentration

TABLE B-10

pH and Interfacial Tension Data for NaOH in Solutions
of 67.20 gm/litre NaCl and Lloydminster Crude Oil

<u>NaOH</u> <u>Concentration</u> <u>Weight Percent</u>	<u>pH</u> <u>Measured</u>	<u>Interfacial Tension</u>	
		<u>Apparent</u> <u>Dynes/cm</u>	<u>Corrected</u> <u>Dynes/cm</u>
0	6.80	22.7	24.4
0.002	9.75	1.5	1.3
0.004	10.10	< 0.4	< 0.4
0.006	10.38	< 0.4	< 0.4
0.008	10.58	< 0.4	< 0.4
0.01	10.70	< 0.4	< 0.4
0.02	11.15	< 0.4	< 0.4
0.04	11.40	< 0.4	< 0.4
0.06	11.55	< 0.4	< 0.4
0.08	11.68	< 0.4	< 0.4
0.10	11.80	< 0.4	< 0.4
0.20	12.04	< 0.4	< 0.4
0.40	12.20	< 0.4	< 0.4
0.60	12.40	< 0.4	< 0.4
0.80	12.50	< 0.4	< 0.4
1.00	12.60	< 0.4	< 0.4
2.00	12.75	< 0.4	< 0.4
4.00	12.82	< 0.4	< 0.4
6.00	12.78	< 0.4	< 0.4
8.00	12.75	< 0.4	< 0.4
10.00	12.64	< 0.4	< 0.4

NOTE: No precipitation formed at any NaOH concentration

Test temperature 75° F throughout test

TABLE B-11

pH and Interfacial Tension Data for NaOH in Solution
of 9.25 gm/litre MgCl₂ and Lloydminster Crude Oil

NaOH Concentration Weight Percent	pH Measured	<u>Interfacial Tension</u>		Temperature ° F	<u>Precipitate</u>
		<u>Apparent</u> Dynes/cm	<u>Corrected</u> Dynes/cm		
0	5.92	23.6	28.3	74	None
0.002	9.05	6.7	6.7	74	Slightly Cloudy
0.004	9.18	5.4	5.2	74	"
0.006	9.12	6.0	5.9	74	"
0.008	9.15	6.5	6.5	74	"
0.01	9.15	6.8	6.8	74	"
0.02	9.18	7.0	7.0	75	Clouded
0.04	9.20	6.0	5.9	75	"
0.06	9.22	6.4	6.4	75	"
0.08	9.25	6.5	6.5	75	"
0.10	9.25	5.9	5.8	75	"
0.20	9.28	5.9	5.8	75	White Precipitate
0.40	9.30	6.4	6.4	76	"
0.60	9.52	6.5	6.5	76	"
0.80	11.92	∠ 0.4	∠ 0.4	76	"
1.00	12.30	∠ 0.4	∠ 0.4	76	"
2.00	12.75	∠ 0.4	∠ 0.4	76	"
4.00	12.93	∠ 0.4	∠ 0.4	76	"
6.00	13.00	∠ 0.4	∠ 0.4	76	"
8.00	13.00	∠ 0.4	∠ 0.4	76	"
10.00	13.00	∠ 0.4	∠ 0.4	76	"

TABLE B-12

pH and Interfacial Tension Data for NaOH in Solution
of 13.55 gm/litre CaCl₂ and Lloydminster Crude Oil

NaOH Concentration Weight Percent	pH Measured	Interfacial Tension		Temperature ° F	Precipitate
		Apparent Dynes/cm	Corrected Dynes/cm		
0	6.15	22.4	26.9	75	None
0.002	9.40	15.6	17.5	75	"
0.004	10.00	15.0	16.8	75	"
0.006	10.18	15.2	17.0	75	"
0.008	10.25	15.0	16.8	75	"
0.01	10.33	15.2	17.0	75	"
0.02	10.80	15.5	17.4	75	"
0.04	11.26	15.5	17.4	75	"
0.06	11.52	16.0	18.0	75	"
0.08	11.65	16.0	18.0	75	"
0.10	11.74	15.8	17.7	75	"
0.20	11.92	16.2	18.3	75	White Precipitate
0.40	11.95	15.8	17.7	76	"
0.60	12.08	16.0	18.0	76	"
0.80	12.18	16.0	18.0	76	"
1.00	12.28	15.5	17.4	76	"
2.00	12.75	10.9	11.6	76	"
4.00	12.90	3.0	2.8	76	"
6.00	12.94	< 0.4	< 0.4	77	"
8.00	12.98	< 0.4	< 0.4	77	"
10.00	13.00	< 0.4	< 0.4	77	"

TABLE B-13

pH and Interfacial Tension Data for NaOH
in Complex Salt Solution and Lloydminster Crude Oil

<u>NaOH</u> <u>Concentration</u> <u>Weight Percent</u>	<u>pH</u> <u>Measured</u>	<u>Interfacial Tension</u>		<u>Temperature</u> <u>° F</u>	<u>Precipitate</u>
		<u>Apparent</u> <u>Dynes/cm</u>	<u>Corrected</u> <u>Dynes/cm</u>		
0	7.06	19.0	19.3	77	None
0.002	7.06	19.0	19.3	77	Slightly Cloudy
0.004	7.08	19.4	19.7	77	"
0.006	7.08	19.3	19.6	77	"
0.008	7.20	18.7	19.0	77	"
0.01	7.60	17.6	17.7	77	"
0.02	8.93	15.6	15.5	77	Slight Gray Precipitate
0.04	9.00	14.9	14.7	77	"
0.06	9.03	15.0	14.8	76	"
0.08	9.03	15.0	14.8	76	"
0.10	9.10	15.0	14.8	76	"
0.20	9.12	14.9	14.7	76	Heavy White Precipitate
0.40	9.16	15.0	14.8	77	"
0.60	9.38	15.5	15.4	77	"
0.80	10.28	16.3	16.3	77	"
1.00	11.83	17.6	17.7	77	"
2.00	12.30	14.0	13.7	77	"
4.00	12.80	3.5	2.8	77	"
6.00	12.85	2.0	1.7	77	"
8.00	12.95	1.7	1.5	77	"
10.00	12.98	1.5	1.3	77	"

TABLE B-14

pH and Interfacial Tension Data for NaOH
in Field Water Sample 2 and Lloydminster Crude Oil

NaOH Concentration Weight Percent	pH Apparent	pH Corrected	Precipitate	Surface Tension		Interfacial Tension		O F Temperature
				Apparent Dynes/cm	Corrected Dynes/cm	Apparent Dynes/cm	Corrected Dynes/cm	
0	7.18	7.18	-	78.6	73.7	19.9	20.3	80
0.0025	6.70	6.70	Trace	77.8	72.6	21.7	22.3	80
0.0050	6.75	6.75	Clouding	78.6	73.7	22.0	22.9	80
0.0075	6.76	6.76	"	80.1	75.4	21.2	21.8	80
0.0100	6.78	6.78	"	78.5	73.5	21.5	22.1	80
0.0125	6.85	6.85	"	78.4	73.4	20.5	21.0	80
0.0150	7.75	7.75	"	78.6	73.7	17.9	18.2	80
0.02	7.90	7.90	"	78.4	73.4	15.8	15.8	81
0.03	8.53	8.53	"	78.3	73.3	14.6	14.4	81
0.04	9.01	9.02	Precipitate	77.8	72.6	14.6	14.4	81
0.05	9.26	9.29	"	77.8	72.6	14.5	14.3	81
0.06	9.35	9.38	"	78.2	73.2	14.2	14.0	81
0.07	9.33	9.36	"	78.0	72.9	14.7	14.5	81
0.08	9.30	9.33	"	78.2	73.2	14.0	13.7	81
0.09	9.30	9.33	"	77.8	72.6	13.2	12.8	81
0.10	9.20	9.22	"	78.5	73.5	13.3	12.9	83
0.12	9.26	9.28	"	78.2	73.2	13.5	13.2	83
0.14	9.35	9.38	"	78.1	73.0	12.6	12.2	83
0.16	9.32	9.35	"	78.3	73.3	14.0	13.7	83
0.18	9.30	9.33	"	77.5	72.2	14.1	13.8	83
0.20	9.29	9.32	"	77.7	72.4	14.0	13.7	83
0.25	9.34	9.37	"	78.6	73.7	13.5	13.2	81
0.30	9.39	9.42	"	77.4	72.0	14.3	14.1	81
0.45	10.61	10.74	"	77.8	72.6	15.8	15.8	81
0.60	11.10	11.34	"	77.6	72.3	16.8	16.8	81
0.75	11.26	11.59	"	78.1	73.0	16.7	16.7	81
0.90	11.30	12.60	"	78.2	73.2	16.3	16.3	81
1.10	11.37	12.72	"	78.1	73.0	15.2	15.0	81
2.5	12.08	12.99	"	78.5	73.5	7.5	7.0	78
5.0	12.20	13.20	"	80.0	75.3	3.6	3.2	78
10.0	12.50	13.50	"	81.0	76.5	2.0	1.7	78

TABLE B-15

pH and Interfacial Tension Data for NaOH
in Various Solutions and Lloydminster Crude Oil

NaOH Concentration Weight Percent	Measured Solution pH	Interfacial Tension Apparent Corrected Dynes/cm Dynes/cm		Remarks
<u>Solution - NaOH in Distilled Water</u>				
0	6.45	26.5	32.2	Temperature - 77.5° F
0.001	9.95	18.0	20.4	
0.005	10.96	11.5	12.2	
0.010	11.43	5.5	5.4	
0.050	11.91	0.8	0.7	
0.100	12.30	0.5	0.4	
0.500	12.68	< 0.4	< 0.4	
1.000	12.80	< 0.4	< 0.4	
5.000	13.06	< 0.4	< 0.4	
10.000	13.16	< 0.4	< 0.4	
<u>Solution - NaOH in Brine</u>				
0	6.75	26.2	27.9	Temperature - 77.8° F
0.001	9.82	2.4	2.1	
0.005	10.55	< 0.4	< 0.4	
0.010	11.13	< 0.4	< 0.4	
0.050	11.86	< 0.4	< 0.4	
0.100	12.06	< 0.4	< 0.4	
0.500	12.40	< 0.4	< 0.4	
1.000	12.81	< 0.4	< 0.4	
5.000	12.90	< 0.4	< 0.4	
10.000	13.10	< 0.4	< 0.4	
<u>Solution - NaOH in Complex Salt Solution</u>				
0	7.10	23.8	24.9	Temperature - 77.8° F
0.001	8.80	16.7	16.8	
0.005	9.75	15.4	15.3	Visible White Precipitate
0.010	9.82	15.1	15.0	
0.050	9.75	15.0	14.8	
0.100	9.55	15.0	14.8	
0.500	9.67	15.6	15.4	
1.000	12.00	17.2	17.2	
5.000	13.15	2.3	2.0	
10.000	13.30	1.0	0.9	

TABLE B-15 (continued)

pH and Interfacial Tension Data for NaOH
in Various Solutions and Lloydminster Crude Oil

NaOH	Measured	<u>Interfacial Tension</u>		<u>Remarks</u>
Concentration	Solution	Apparent	Corrected	
<u>Weight Percent</u>	<u>pH</u>	<u>Dynes/cm</u>	<u>Dynes/cm</u>	
<u>Solution - NaOH in Field Water</u>				
0	7.51	21.5	22.3	Temperature - 77.8° F
0.001	7.96	17.0	17.1	
0.005	8.89	15.3	15.2	
0.010	10.00	14.6	14.5	Visible White Precipitate
0.050	9.97	14.0	13.8	"
0.100	10.09	15.0	14.9	"
0.500	11.45	15.9	15.8	"
1.000	12.36	15.9	15.7	"
5.000	13.11	2.9	2.5	"
10.000	13.17	1.0	0.9	"

TABLE B-16

pH and Interfacial Tension Data for KOH in
Various Solutions and Lloydminster Crude Oil

KOH Concentration Weight Percent	Measured Solution pH	<u>Interfacial Tension</u> Apparent Corrected Dynes/cm Dynes/cm		<u>Remarks</u>
<u>Solution - KOH in Distilled Water</u>				
0	6.70	25.0	30.1	Temperature - 79° F
0.001	10.31	14.5	15.9	
0.005	10.86	11.3	12.0	
0.010	11.25	9.2	9.5	
0.050	12.10	0.7	0.6	
0.100	12.25	< 0.4	< 0.4	
0.500	12.62	< 0.4	< 0.4	
1.000	12.95	< 0.4	< 0.4	
5.000	13.42	< 0.4	< 0.4	
10.000	13.60	< 0.4	< 0.4	
<u>Solution - KOH in Brine</u>				
0	7.34	26.7	28.5	Temperature - 79° F
0.001	9.63	4.2	3.8	
0.005	10.35	0.8	0.7	
0.010	10.78	< 0.4	< 0.4	
0.050	11.54	< 0.4	< 0.4	
0.100	11.80	< 0.4	< 0.4	
0.500	12.30	< 0.4	< 0.4	
1.000	12.60	< 0.4	< 0.4	
5.000	13.09	< 0.4	< 0.4	
10.000	13.25	< 0.4	< 0.4	
<u>Solution - KOH in Complex Salt Solution</u>				
0	7.27	23.5	24.6	Temperature - 79° F
0.001	8.11	15.5	15.4	
0.005	9.38	14.8	14.7	Visible Fine, White Powdery Precipitate
0.010	9.51	15.2	15.1	
0.050	9.52	14.9	14.7	
0.100	9.25	14.6	14.4	
0.500	9.37	15.3	15.1	
1.000	9.98	15.0	14.7	
5.000	13.01	4.2	3.7	
10.000	13.26	1.5	1.3	

TABLE B-16 (continued)pH and Interfacial Tension Data for KOH in
Various Solutions and Lloydminster Crude Oil

KOH Concentration <u>Weight Percent</u>	Measured Solution <u>pH</u>	<u>Interfacial Tension</u>		<u>Remarks</u>
		<u>Apparent</u> <u>Dynes/cm</u>	<u>Corrected</u> <u>Dynes/cm</u>	
<u>Solution - KOH in Field Water</u>				
0	7.50	21.5	22.3	Temperature - 79° F
0.001	7.80	18.7	19.2	
0.005	8.21	15.2	15.1	
0.010	8.57	14.8	14.7	
0.050	9.78	13.9	13.7	Visible White Precipitate
0.100	9.89	14.4	14.2	"
0.500	10.05	15.5	15.4	"
1.000	12.14	16.4	16.3	"
5.000	13.05	4.2	3.7	"
10.000	13.25	2.0	1.7	"

TABLE B-17

pH and Interfacial Tension Data for Na₄EDTA
in Various Solutions and Lloydminster Crude Oil

Na ₄ EDTA Concentration <u>Weight Percent</u>	Measured Solution <u>pH</u>	<u>Interfacial Tension</u> Apparent Corrected <u>Dynes/cm</u> <u>Dynes/cm</u>		<u>Remarks</u>
<u>Solution - Na₄EDTA in Distilled Water</u>				
0	7.20	24.5	29.4	Temperature - 78° F
0.001	7.32	24.1	28.8	
0.005	9.75	25.2	30.4	
0.010	10.05	21.9	25.7	
0.050	10.62	12.9	13.9	
0.100	10.70	10.8	11.3	
0.500	10.75	3.5	3.3	
1.000	10.70	< 0.4	< 0.4	
5.000	10.80	< 0.4	< 0.4	
10.000	10.70	< 0.4	< 0.4	
<u>Solution - Na₄EDTA in Brine</u>				
0	6.72	25.4	26.9	Temperature - 80° F
0.0002	7.47	24.2	25.5	
0.001	7.37	24.8	26.2	
0.002	7.92	24.1	25.4	
0.005	8.38	19.3	19.8	
0.010	8.72	14.3	14.1	
0.020	8.95	10.2	9.8	
0.050	9.32	6.0	5.5	
0.100	9.47	1.5	1.3	
0.200	9.61	< 0.4	< 0.4	
0.500	9.75	< 0.4	< 0.4	
1.000	9.92	< 0.4	< 0.4	
2.000	10.03	< 0.4	< 0.4	
5.000	10.10	< 0.4	< 0.4	
10.000	10.18	< 0.4	< 0.4	

TABLE B-17 (continued)

pH and Interfacial Tension Data for Na₄EDTA
in Various Solutions and Lloydminster Crude Oil

<u>Na₄EDTA</u>	<u>Measured</u>	<u>Interfacial Tension</u>		<u>Remarks</u>
<u>Concentration</u>	<u>Solution</u>	<u>Apparent</u>	<u>Corrected</u>	
<u>Weight Percent</u>	<u>pH</u>	<u>Dynes/cm</u>	<u>Dynes/cm</u>	
<u>Solution - Na₄EDTA in Complex Salt Solution</u>				
0	6.95	23.2	24.2	Temperature - 80° F
0.0002	6.98	23.4	24.5	
0.001	6.70	23.3	24.4	
0.002	6.97	22.9	23.9	
0.005	6.99	23.0	24.0	
0.010	7.02	22.0	22.8	
0.020	7.03	21.5	22.2	
0.050	7.13	22.5	23.4	
0.100	7.15	22.4	23.3	
0.200	7.20	23.0	24.0	
0.500	7.28	21.4	22.0	
1.000	7.50	19.5	19.7	
2.000	7.66	17.2	17.0	
5.000	8.03	15.1	14.5	
7.500	8.35	14.1	13.2	
10.000	9.40	0.5	0.4	
<u>Solution - Na₄EDTA in Field Water</u>				
0	7.36	18.7	19.0	Temperature - 80° F
0.0002	7.32	18.6	18.9	
0.001	7.30	19.1	19.5	
0.002	7.44	18.2	18.5	
0.005	7.40	16.8	16.9	
0.010	7.35	17.3	17.4	
0.020	7.48	17.9	18.1	
0.050	7.44	17.8	18.0	
0.100	7.46	18.6	18.9	
0.200	7.46	16.8	16.9	
0.500	7.58	16.8	16.8	
1.000	7.96	17.2	17.2	
2.000	8.00	16.8	16.6	
5.000	8.76	11.0	10.3	
10.000	9.81	1.7	1.5	

TABLE B-18

pH and Interfacial Tension Data for Na₂CO₃
in Various Solutions and Lloydminster Crude Oil

<u>Na₂CO₃</u>	<u>Measured</u>	<u>Interfacial Tension</u>		<u>Remarks</u>
<u>Concentration</u>	<u>Solution</u>	<u>Apparent</u>	<u>Corrected</u>	
<u>Weight Percent</u>	<u>pH</u>	<u>Dynes/cm</u>	<u>Dynes/cm</u>	
<u>Solution - Na₂CO₃ in Distilled Water</u>				
0	6.52	25.2	30.4	Temperature - 76.5° F
0.001	9.62	22.8	27.0	
0.005	10.34	17.1	19.3	
0.010	10.64	13.1	14.2	
0.050	10.98	9.2	9.5	
0.100	11.13	3.8	3.6	
0.500	11.33	∠ 0.4	∠ 0.4	
1.000	11.47	∠ 0.4	∠ 0.4	
5.000	11.65	∠ 0.4	∠ 0.4	
10.000	11.78	∠ 0.4	∠ 0.4	

Solution - Na₂CO₃ in Brine

0	7.50	25.5	27.1	Temperature - 77° F
0.001	8.97	15.1	15.0	
0.005	9.46	6.1	5.7	
0.010	9.68	1.0	0.9	
0.050	10.15	∠ 0.4	∠ 0.4	
0.100	10.42	∠ 0.4	∠ 0.4	
0.500	10.67	∠ 0.4	∠ 0.4	
1.000	10.84	∠ 0.4	∠ 0.4	
5.000	11.13	∠ 0.4	∠ 0.4	

Solution - Na₂CO₃ in Complex Salt Solution

0.100	8.93	15.7	15.6	Temperature - 80° F Precipitate*
1.000	8.45	14.3	14.0	

Solution - Na₂CO₃ in Field Water

0.100	8.68	14.5	14.3	Temperature - 80° F Precipitate*
1.000	9.37	8.6	8.0	

*White gelatinous precipitate formed when Na₂CO₃ added to Complex Salt Solution and Field Water

TABLE B-19

pH and Interfacial Tension Data for $(\text{NaPO}_3)_6$
in Various Solutions and Lloydminster Crude Oil

$(\text{NaPO}_3)_6$ Concentration Weight Percent	Measured Solution pH	<u>Interfacial Tension</u>		Remarks
		Apparent Dynes/cm	Corrected Dynes/cm	
<u>Solution - $(\text{NaPO}_3)_6$ in Distilled Water</u>				
0	6.27	25.3	30.5	Temperature - 77° F
0.001	6.58	25.0	30.1	
0.005	7.52	25.3	30.5	
0.010	8.06	24.5	29.4	
0.050	8.00	24.1	28.8	
0.100	7.83	24.7	29.5	
0.500	7.50	23.3	27.2	
1.000	7.30	23.5	27.0	
5.000	6.76	24.3	25.9	
10.000	6.58	25.1	25.5	
<u>Solution - $(\text{NaPO}_3)_6$ in Brine</u>				
0	6.63	20.9	21.6	Temperature - 76° F
0.001	6.52	23.8	25.0	
0.005	6.15	25.5	27.1	
0.010	5.90	24.4	25.8	
0.050	5.64	26.0	27.7	
0.100	5.57	27.1	29.0	
0.500	5.53	27.1	28.8	
1.000	5.53	27.5	29.1	
5.000	5.49	28.5	29.2	
10.000	5.49	29.9	29.8	
<u>Solution - $(\text{NaPO}_3)_6$ in Complex Salt Solution</u>				
0.100	5.15	27.1	28.9	Temperature - 80° F Precipitate*
1.000	4.08	27.5	29.0	
<u>Solution - $(\text{NaPO}_3)_6$ in Field Water</u>				
0.100	5.68	25.7	27.2	Temperature - 80° F Precipitate*
1.000	4.43	26.6	28.1	

*White precipitate formed when $(\text{NaPO}_3)_6$ added to Complex Salt Solution and Field Water

TABLE B-20

pH and Interfacial Tension Data for Na₅P₃O₁₀
in Various Solutions and Lloydminster Crude Oil

Na ₅ P ₃ O ₁₀ Concentration Weight Percent	Measured Solution pH	Interfacial Tension		Remarks	
		Apparent Dynes/cm	Corrected Dynes/cm		
<u>Solution - Na₅P₃O₁₀ in Distilled Water</u>					
0	6.35	24.8	29.6	Temperature - 78° F	
0.001	7.55	24.9	29.8		
0.005	9.07	23.1	27.4		
0.010	9.40	22.3	26.3		
0.050	9.89	17.8	20.2		
0.100	9.95	15.5	17.1		
0.500	9.90	12.1	12.8		
1.000	9.90	10.5	10.8		
5.000	9.60	9.1	8.7		
10.000	9.46	9.3	8.6		
<u>Solution - Na₅P₃O₁₀ in Brine</u>					
0	7.10	22.6	23.8	Temperature - 78° F	
0.001	7.10	24.1	25.4		
0.005	7.15	24.0	25.2		
0.010	7.30	24.1	25.4		
0.050	7.60	21.4	22.2		
0.100	7.86	19.7	20.2		
0.500	8.27	16.5	16.5		
1.000	8.40	15.6	15.4		
5.000	8.49	13.7	13.0		Saturated Solution "
10.000	8.51	14.1	13.1		
<u>Solution - Na₅P₃O₁₀ in Complex Salt Solution</u>					
0.100	6.70	25.5	24.9	Temperature - 81° F Precipitate*	
1.000	5.86	28.1	29.8		
<u>Solution - Na₅P₃O₁₀ in Field Water</u>					
0.100	7.45	23.2	24.3	Temperature - 81° F Precipitate*	
1.000	6.46	25.9	27.2		

*White precipitate formed when Na₅P₃O₁₀ added to Complex Salt Solution and Field Water

TABLE B-21

pH and Interfacial Tension Data for Na₃PO₄
in Various Solutions and Lloydminster Crude Oil

Na3PO4 Concentration Weight Percent	Measured Solution pH	Interfacial Tension Apparent Corrected Dynes/cm Dynes/cm		Remarks
<u>Solution - Na3PO4 in Distilled Water</u>				
0	6.62	25.2	30.4	Temperature - 78° F
0.001	8.25	23.4	27.8	
0.005	9.86	19.7	22.7	
0.010	10.25	16.5	18.5	
0.050	11.16	8.7	8.9	
0.100	11.42	3.2	3.0	
0.500	11.90	< 0.4	< 0.4	
1.000	12.05	< 0.4	< 0.4	
5.000	12.51	< 0.4	< 0.4	
10.000	12.70	< 0.4	< 0.4	
<u>Solution - Na3PO4 in Brine</u>				
0	7.10	25.6	27.2	Temperature - 78° F
0.001	7.25	23.0	24.1	
0.005	8.56	18.1	18.4	
0.010	9.08	11.0	10.6	
0.050	10.20	0.8	0.8	
0.100	10.53	< 0.4	< 0.4	
0.500	11.03	< 0.4	< 0.4	
1.000	11.23	< 0.4	< 0.4	
5.000	11.52	< 0.4	< 0.4	
10.000	11.86	< 0.4	< 0.4	Saturated Solution
<u>Solution - Na3PO4 in Complex Salt Solution</u>				
0.100	8.35	17.2	17.3	Temperature - 81° F Precipitate*
1.000	11.36	< 0.4	< 0.4	
<u>Solution - Na3PO4 in Field Water</u>				
0.100	7.93	17.4	17.5	Temperature - 81° F Precipitate*
1.000	8.75	14.7	14.4	

*White precipitate formed when Na₃PO₄ added to Complex Salt Solution and Field Water

TABLE B-22

pH and Interfacial Tension Data for Na₄P₂O₇
in Various Solutions and Lloydminster Crude Oil

Na ₄ P ₂ O ₇ Concentration <u>Weight Percent</u>	Measured Solution <u>pH</u>	<u>Interfacial Tension</u>		<u>Remarks</u>
		<u>Apparent</u> <u>Dynes/cm</u>	<u>Corrected</u> <u>Dynes/cm</u>	
<u>Solution - Na₄P₂O₇ in Distilled Water</u>				
0.100	10.31	13.6	14.8	Temperature - 80° F
1.000	10.36	5.3	5.1	
<u>Solution - Na₄P₂O₇ in Brine</u>				
0.100	8.84	12.9	12.6	
1.000	9.34	6.6	6.1	
<u>Solution - Na₄P₂O₇ in Complex Salt Solution</u>				
0.100	7.25	24.8	26.2	White Precipitate
<u>Solution - Na₄P₂O₇ in Field Water</u>				
0.100	7.47	21.2	21.9	White Precipitate.

TABLE B-23

pH and Interfacial Tension Data for Various
Aqueous Solutions and Oils

<u>Oil Phase</u>	Measured	<u>Interfacial Tension</u>	
	<u>Aqueous Solution</u> <u>pH</u>	<u>Apparent</u> <u>Dynes/cm</u>	<u>Corrected</u> <u>Dynes/cm</u>
<u>Aqueous Solution - Distilled Water</u>			
Varsol	6.20	39.8	40.8
Iso-octane	6.20	42.5	42.1
Varsol-Crude	6.25	22.7	22.2
Iso-octane-Crude	6.20	20.5	19.3
Lloydminster Crude	6.30	25.8	31.2
<u>Aqueous Solution - Brine</u>			
Varsol	6.82	43.7	44.2
Iso-octane	6.90	44.7	43.7
Varsol-Crude	6.92	24.3	22.3
Iso-octane-Crude	6.95	22.6	21.1
Lloydminster Crude	6.95	27.5	29.5
<u>Aqueous Solution - Complex Salt Solution</u>			
Varsol	6.85	42.6	42.9
Iso-octane	7.32	44.6	43.6
Varsol-Crude	7.38	19.7	18.6
Iso-octane-Crude	7.37	21.8	20.3
Lloydminster Crude	7.38	25.6	27.1
<u>Aqueous Solution - Field Water</u>			
Varsol	7.55	38.4	38.3
Iso-octane	7.54	39.8	38.5
Varsol-Crude	7.55	20.8	19.5
Iso-octane-Crude	7.55	18.5	17.0
Lloydminster Crude	7.53	22.1	23.0

Remarks: Temperature during tests - 75.5° F

TABLE B-24

pH and Interfacial Tension Data for NaOH
in Brine and Various Oils

NaOH Concentration <u>Weight Percent</u>	Measured Solution <u>pH</u>	<u>Interfacial Tension</u>	
		<u>Apparent</u> <u>Dynes/cm</u>	<u>Corrected</u> <u>Dynes/cm</u>
<u>Oil Phase - Varsol</u>			
0	6.82	43.7	44.2
0.010	11.13	36.4	36.1
0.100	12.06	35.2	34.7
1.000	12.81	37.5	37.1
10.000	13.10	31.8	30.2
<u>Oil Phase - Iso-octane</u>			
0	6.90	44.7	43.7
0.010	10.91	33.6	33.0
0.100	11.82	35.8	35.4
1.000	12.63	35.4	34.8
10.000	13.07	29.0	27.3
<u>Oil Phase - Varsol-Lloydminster Crude Mixture</u>			
0	6.92	24.3	22.3
0.010	10.90	∠ 0.4	∠ 0.4
0.050	11.86	∠ 0.4	∠ 0.4
0.100	12.04	∠ 0.4	∠ 0.4
0.500	12.40	∠ 0.4	∠ 0.4
1.000	12.63	∠ 0.4	∠ 0.4
5.000	12.90	∠ 0.4	∠ 0.4
10.000	13.00	∠ 0.4	∠ 0.4
<u>Oil Phase - Iso-octane-Lloydminster Crude Mixture</u>			
0	6.95	22.6	21.1
0.010	10.90	∠ 0.4	∠ 0.4
0.100	11.82	∠ 0.4	∠ 0.4
1.000	12.63	∠ 0.4	∠ 0.4
5.000	13.13	∠ 0.4	∠ 0.4
10.000	12.95	∠ 0.4	∠ 0.4

Remarks: Temperature during tests - 77° F

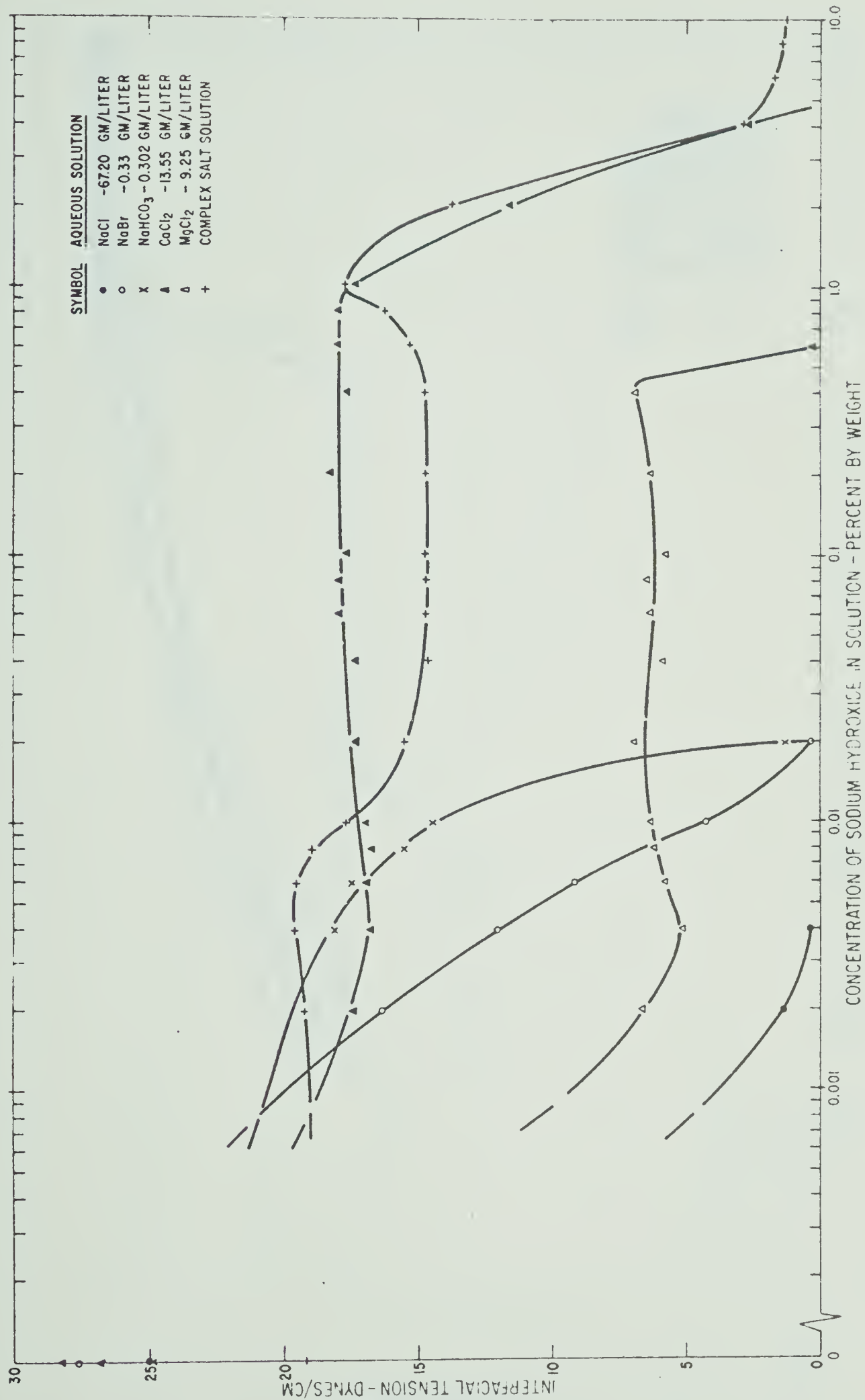


FIG. B-1 - INFLUENCE OF COMPONENTS OF A FIELD WATER SAMPLE ON THE INTERFACIAL TENSION OF LLOYDMINSTER CRUDE OIL AND SODIUM HYDROXIDE SOLUTIONS

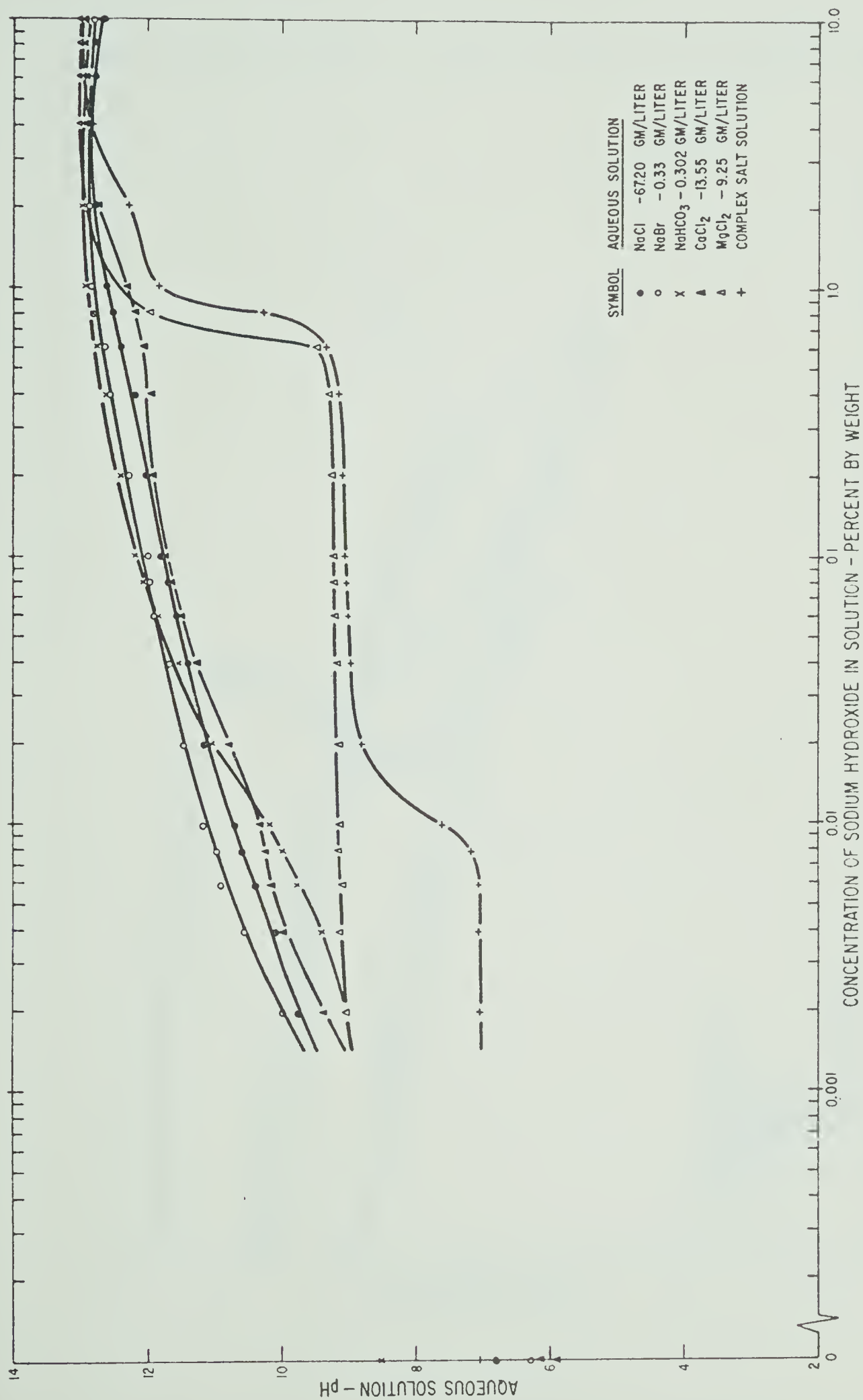


FIG. B-2- SOLUTION pH MEASUREMENTS OF CHEMICAL COMPONENTS
OF A FIELD WATER SAMPLE IN SODIUM HYDROXIDE SOLUTIONS

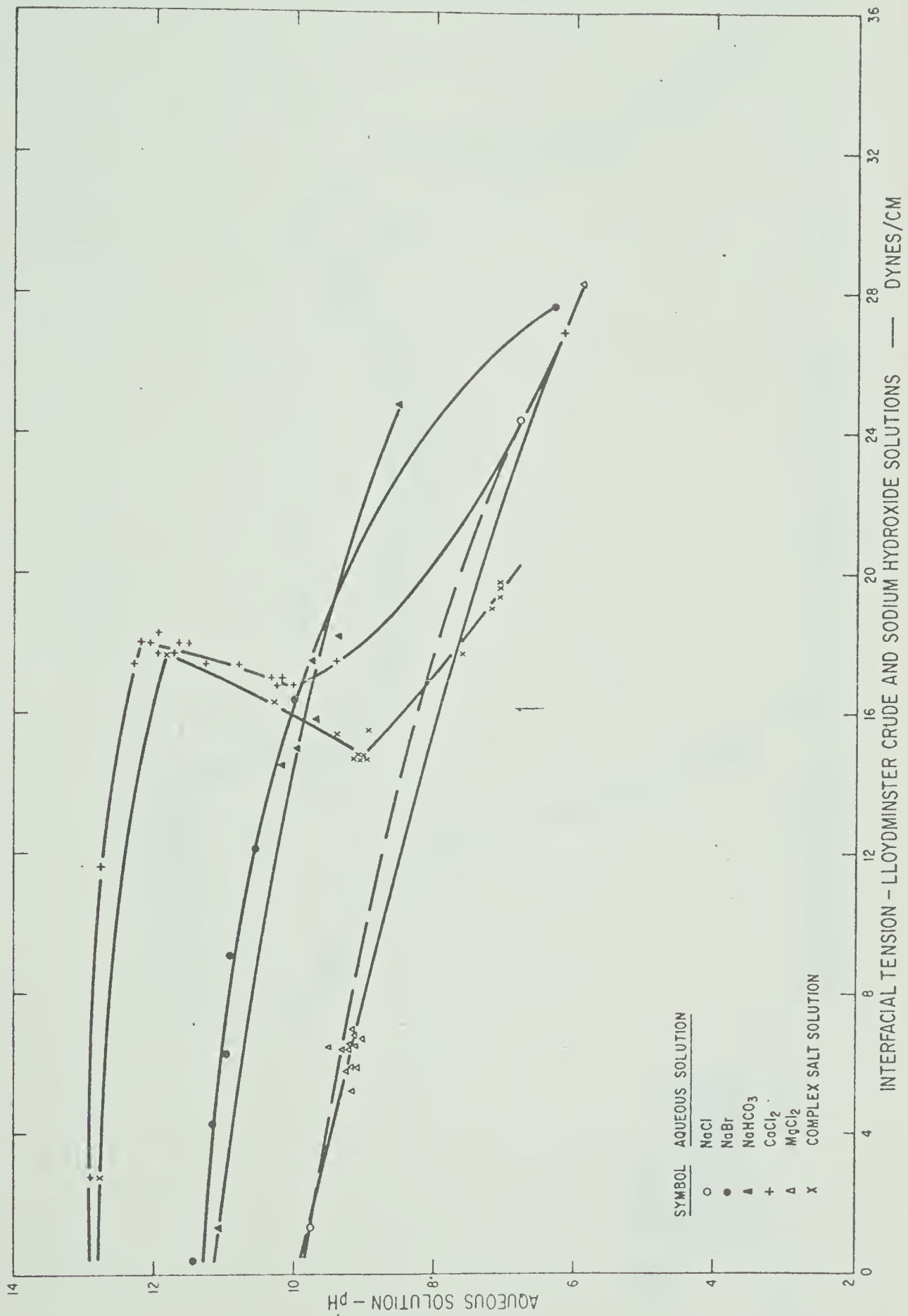


FIG.B-3-RELATIONSHIP OF AQUEOUS SOLUTION pH AND INTERFACIAL TENSION FOR SODIUM HYDROXIDE SOLUTIONS WITH COMPONENTS OF A FIELD WATER SAMPLE AND LLOYDMINSTER CRUDE OIL

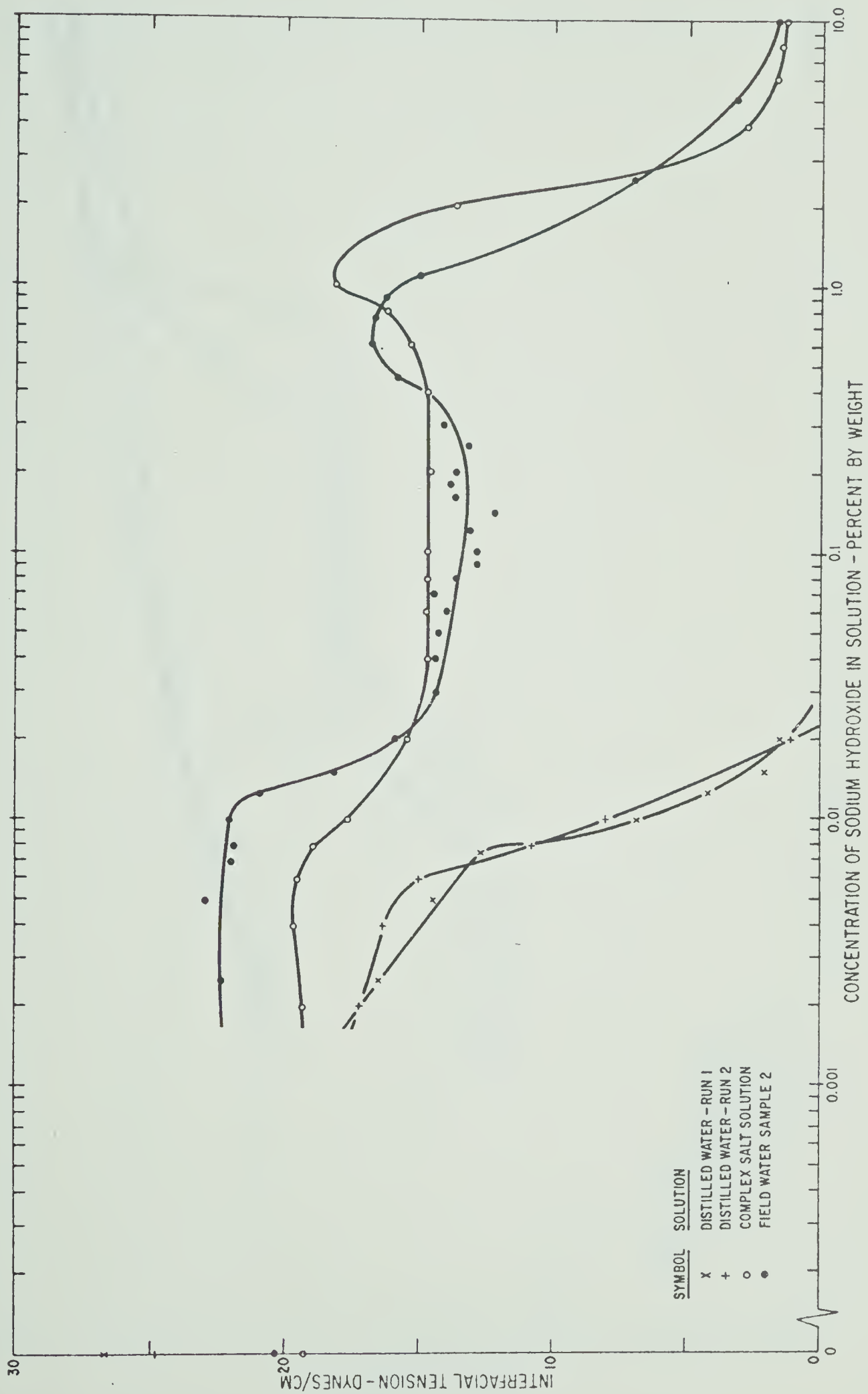


FIG.B-4 - COMPARISON OF INTERFACIAL TENSION MEASUREMENTS FOR SODIUM HYDROXIDE IN FIELD WATER AND A COMPLEX SALT SOLUTION

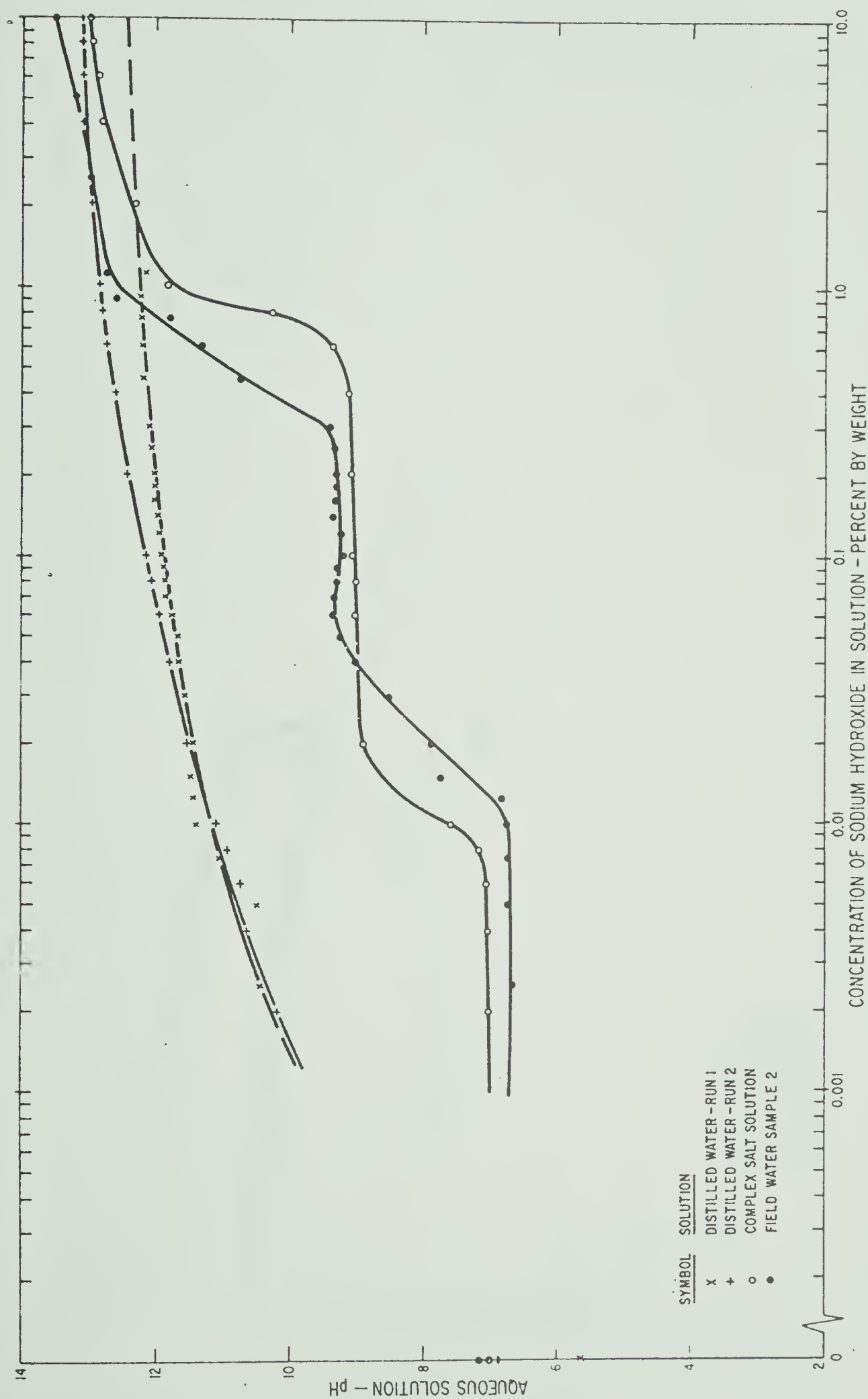


FIG. B - 5 - COMPARISON OF pH MEASUREMENTS FOR SODIUM HYDROXIDE
IN FIELD WATER AND A COMPLEX SALT SOLUTION

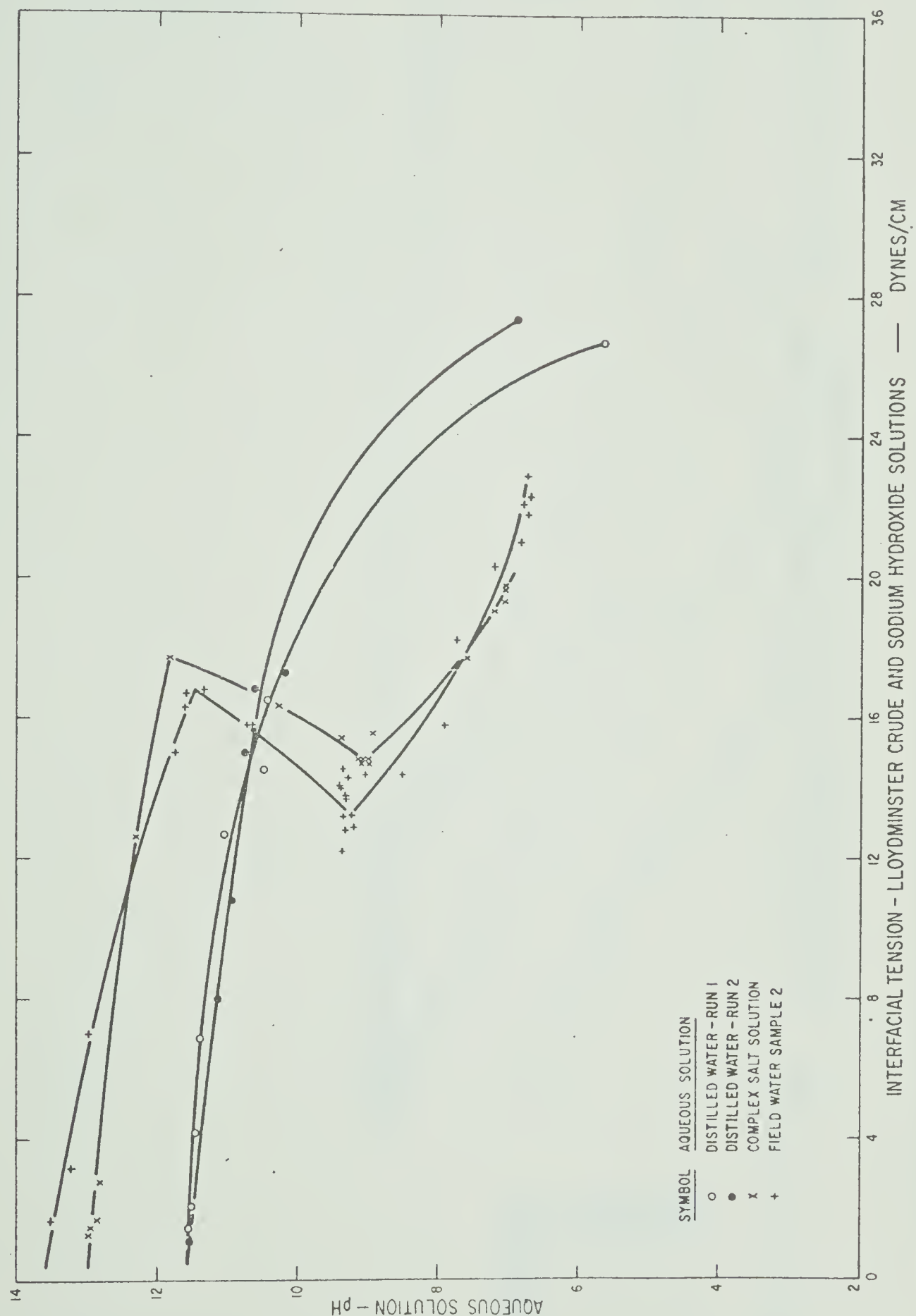


FIG. B - 6- RELATIONSHIP OF AQUEOUS SOLUTION pH AND INTERFACIAL TENSION FOR SODIUM HYDROXIDE SOLUTIONS AND LLOYDMINSTER CRUDE OIL

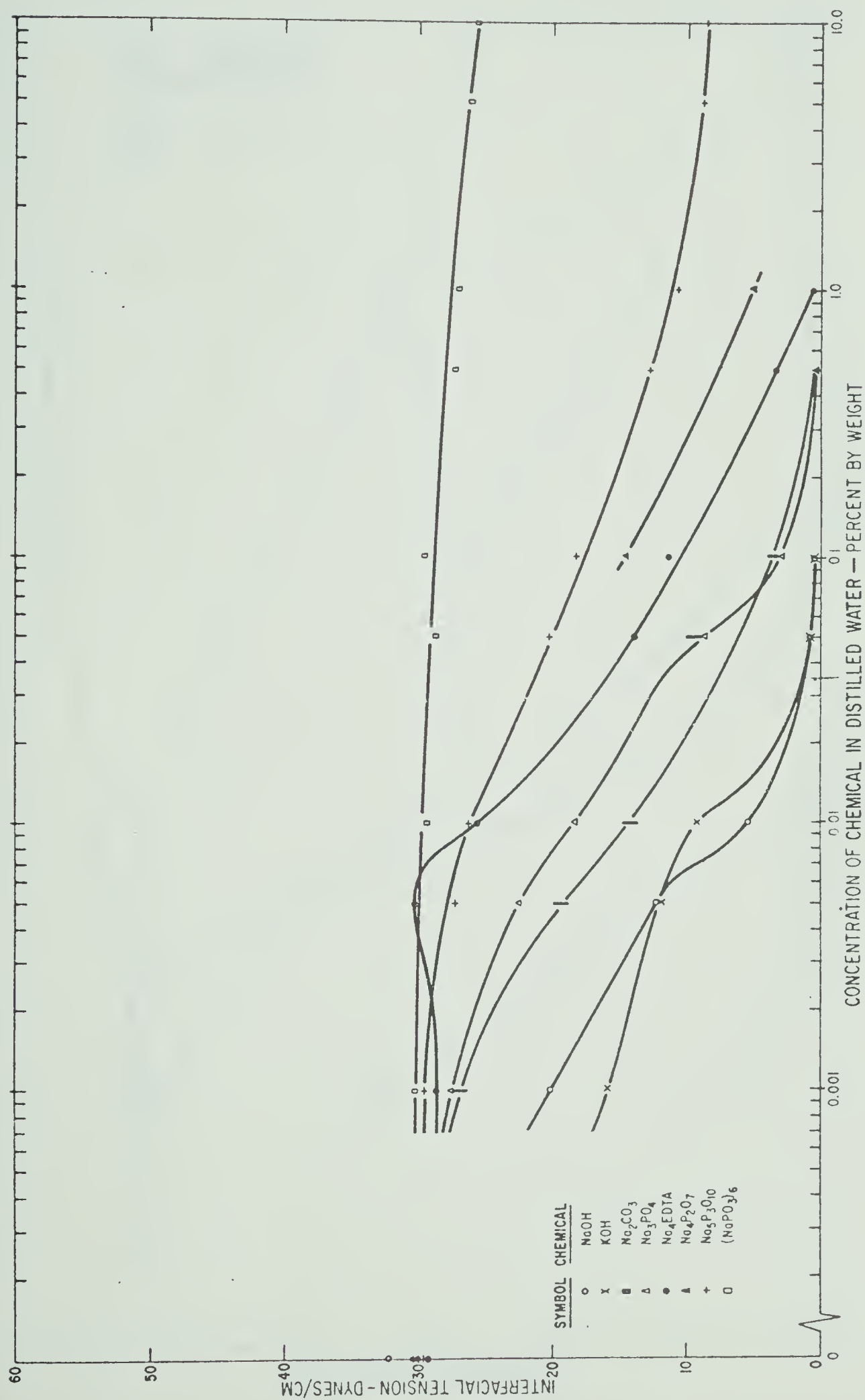


FIG. B - 7 - INFLUENCE OF VARIOUS CHEMICALS IN DISTILLED WATER ON THE INTERFACIAL TENSION OF LLOYDMINSTER CRUDE OIL

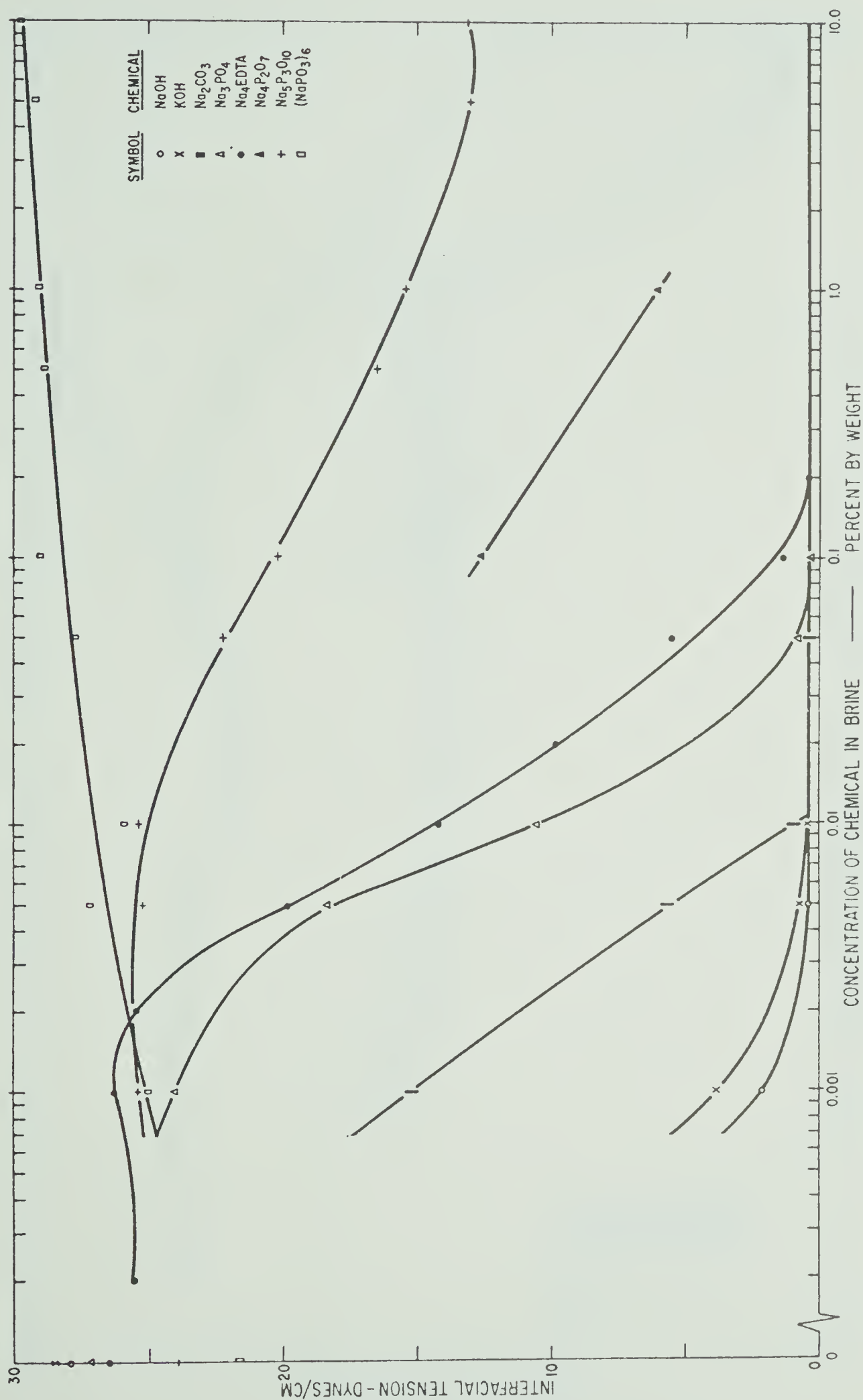


FIG. B-8- INFLUENCE OF VARIOUS CHEMICALS IN BRINE ON THE INTERFACIAL TENSION OF LLOYDMINSTER CRUDE OIL

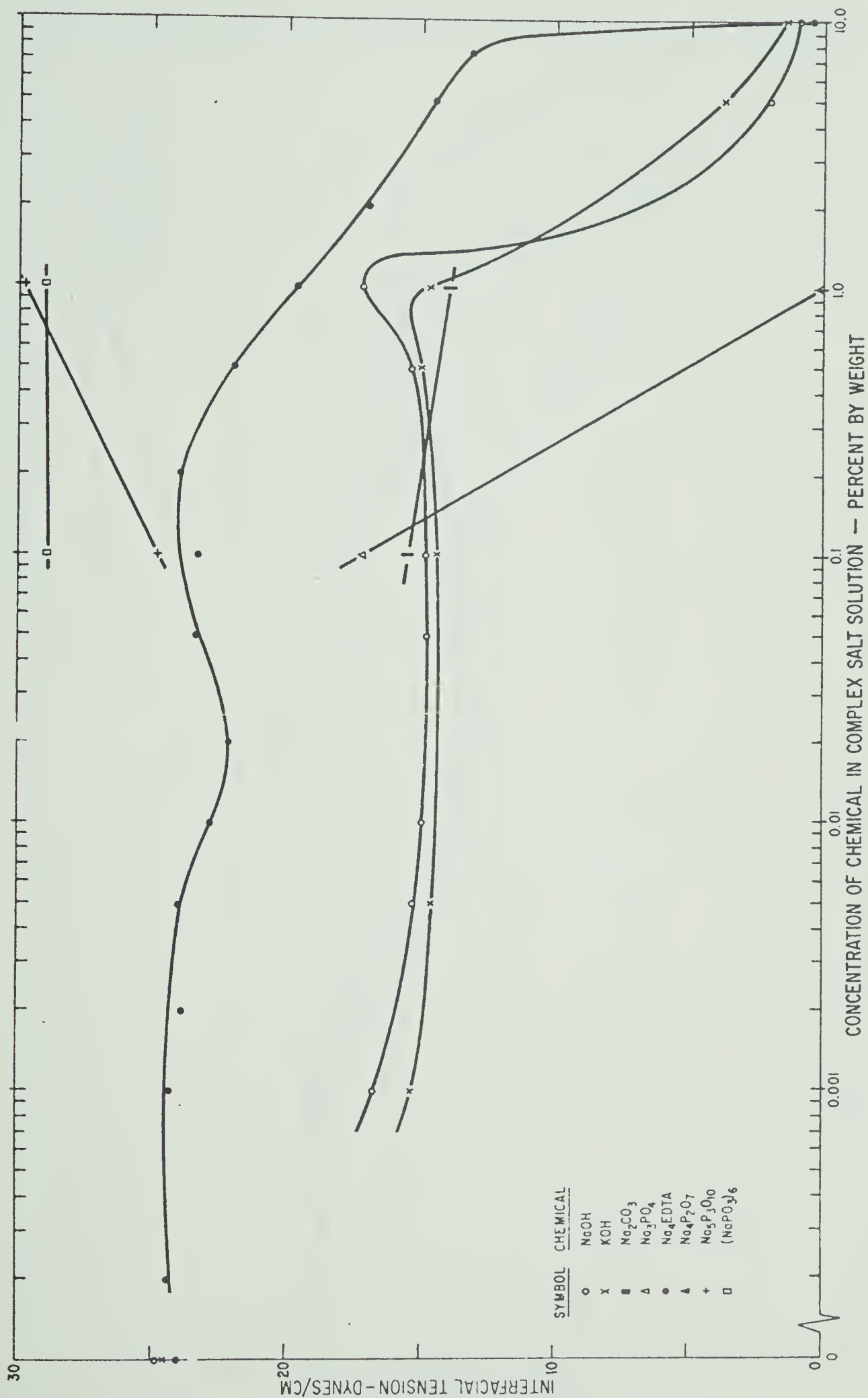


FIG. B - 9 - INFLUENCE OF VARIOUS CHEMICALS IN COMPLEX SALT SOLUTION ON THE INTERFACIAL TENSION OF LLOYDMINSTER CRUDE OIL

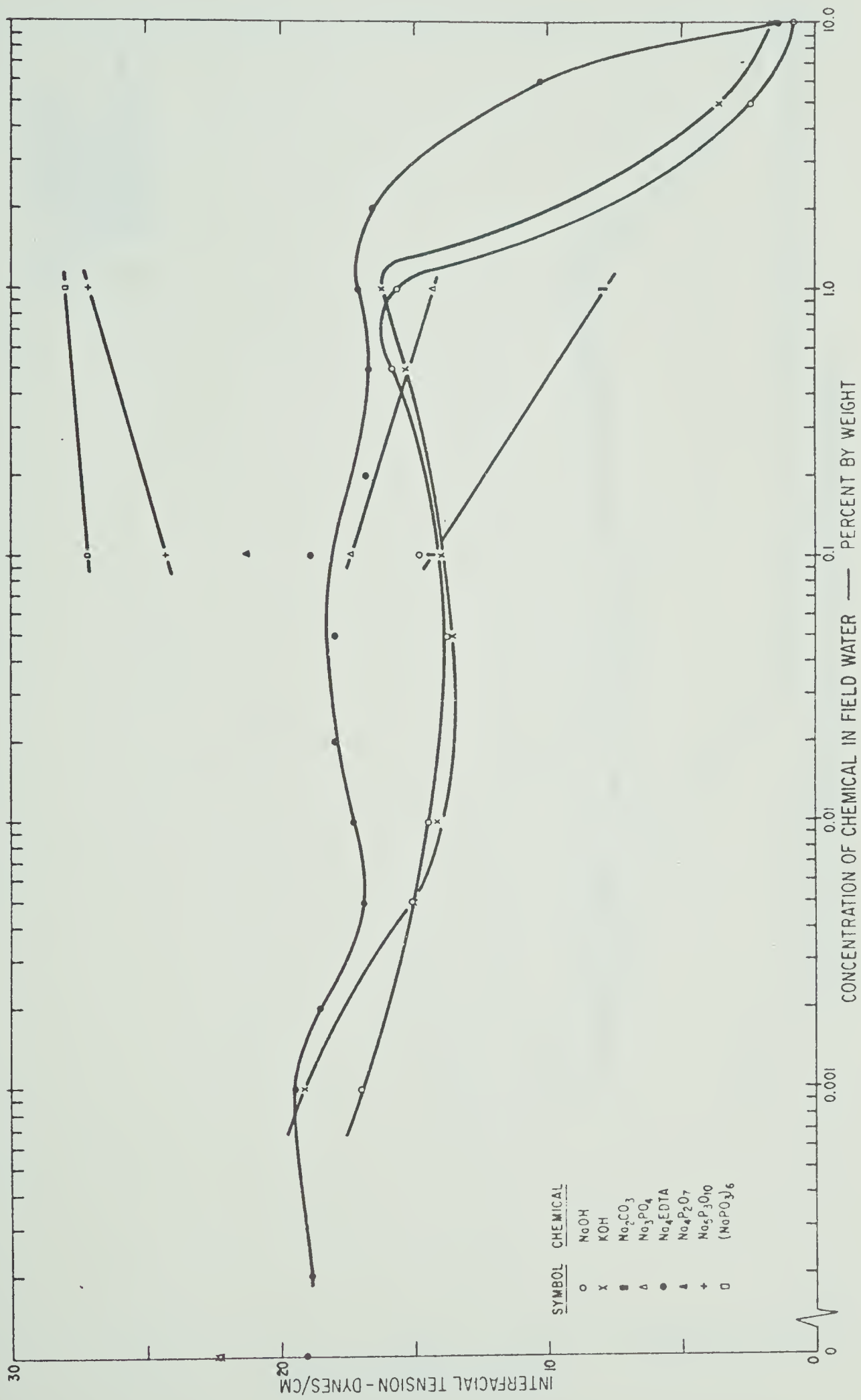


FIG. B - 10- INFLUENCE OF VARIOUS CHEMICALS IN FIELD WATER ON THE INTERFACIAL TENSION OF LLOYDMINSTER CRUDE OIL

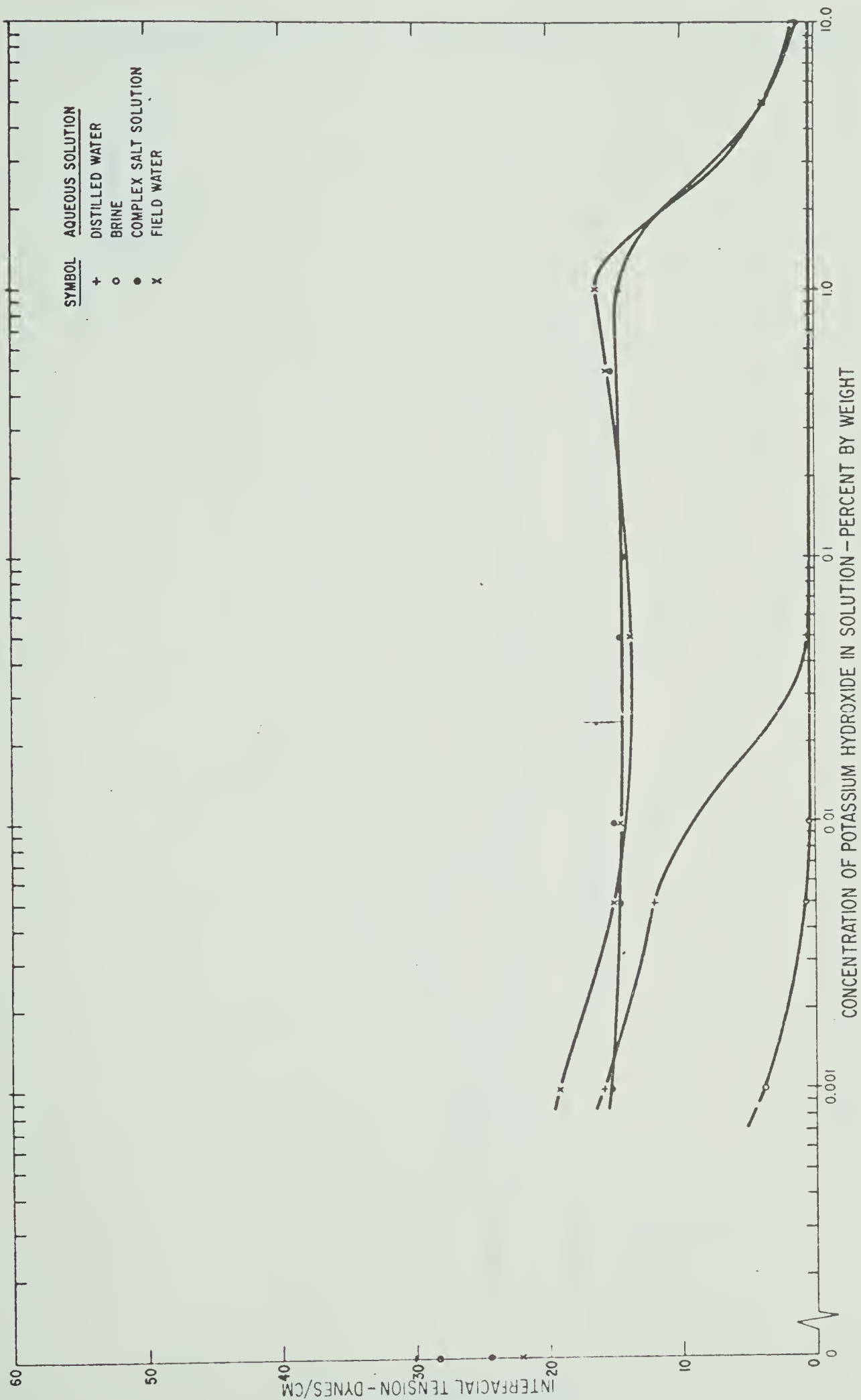


FIG. B - 11 - INFLUENCE OF POTASSIUM HYDROXIDE CONCENTRATION ON THE INTERFACIAL TENSION OF LLOYDMINSTER CRUDE OIL

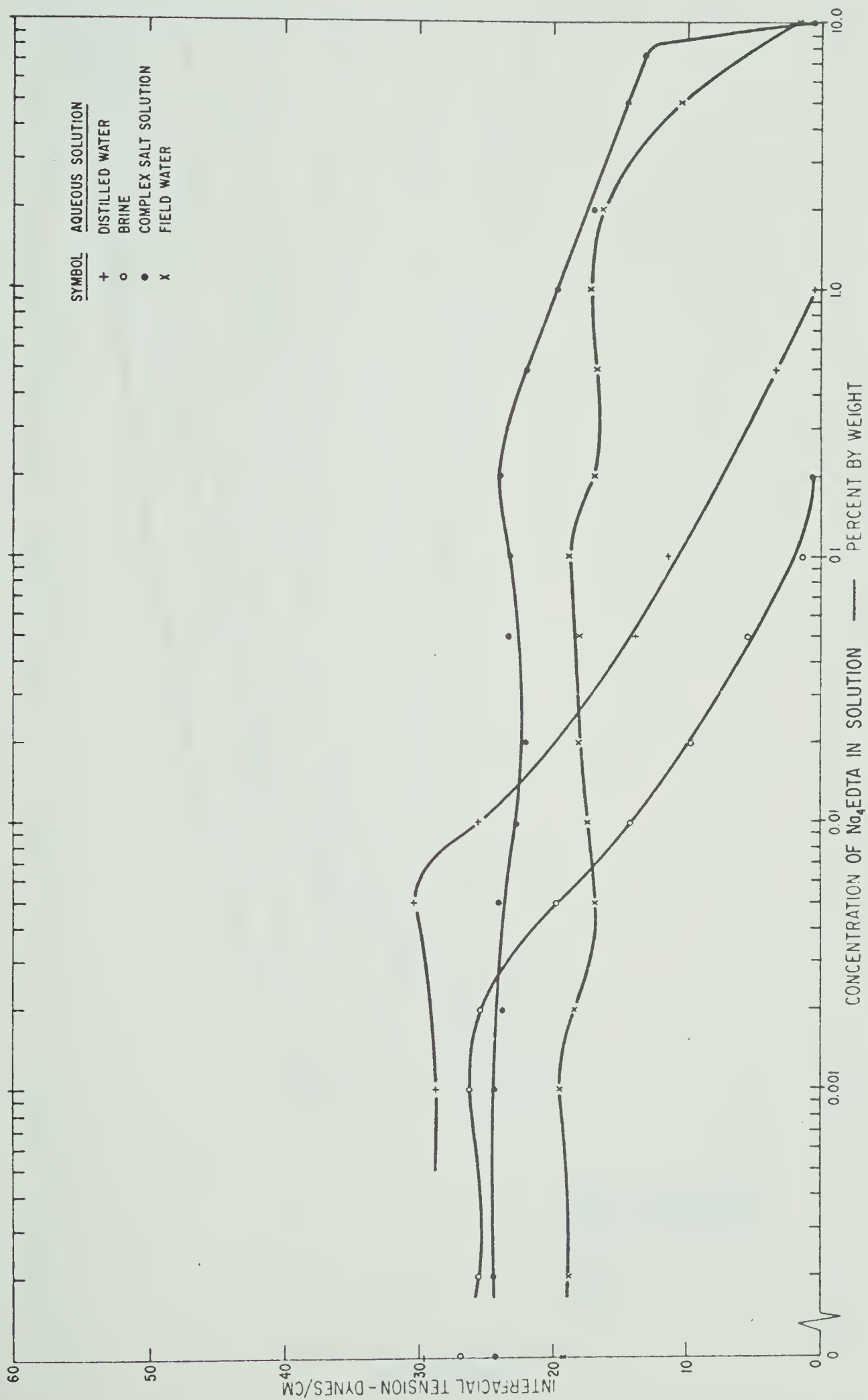


FIG. B - 12 - INFLUENCE OF Na_4EDTA CONCENTRATION ON THE INTERFACIAL TENSION OF LLOYDMINSTER CRUDE OIL

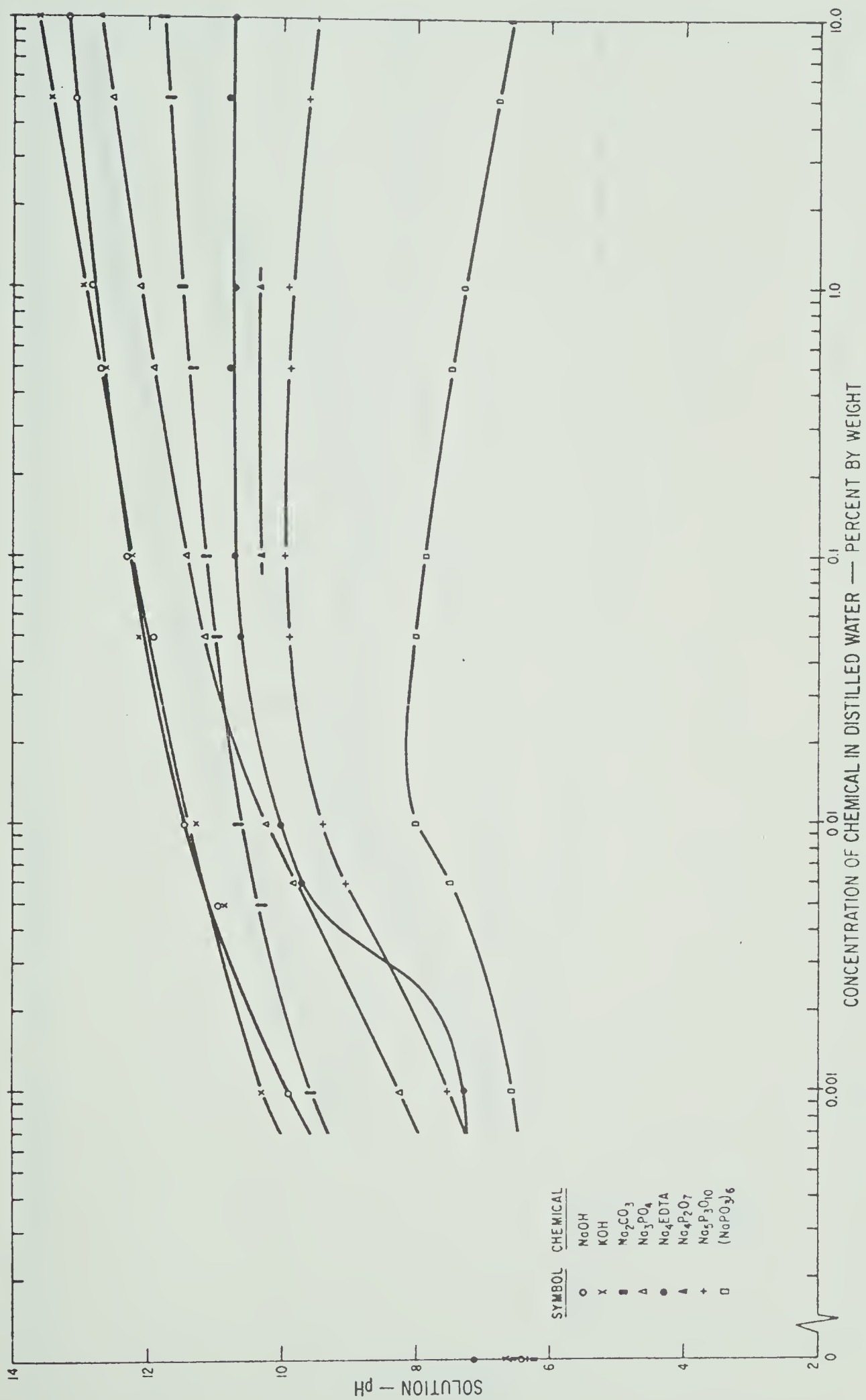


FIG. B - 13 - SOLUTION pH MEASUREMENTS OF VARIOUS CHEMICALS IN DISTILLED WATER



FIG. B-14 - SOLUTION pH MEASUREMENTS OF VARIOUS CHEMICALS IN BRINE

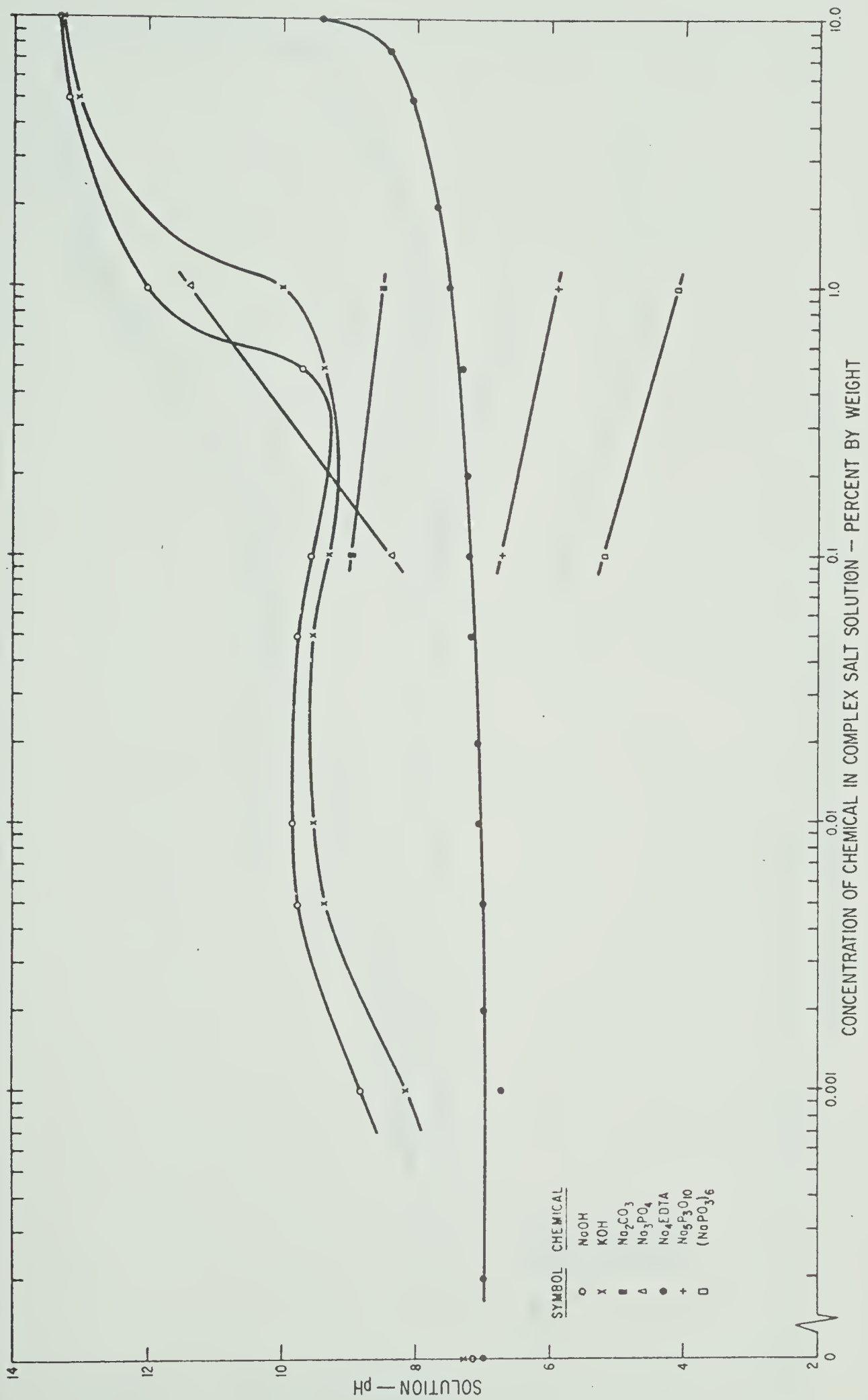


FIG. B-15 - SOLUTION pH MEASUREMENTS OF VARIOUS CHEMICALS IN COMPLEX SALT SOLUTION

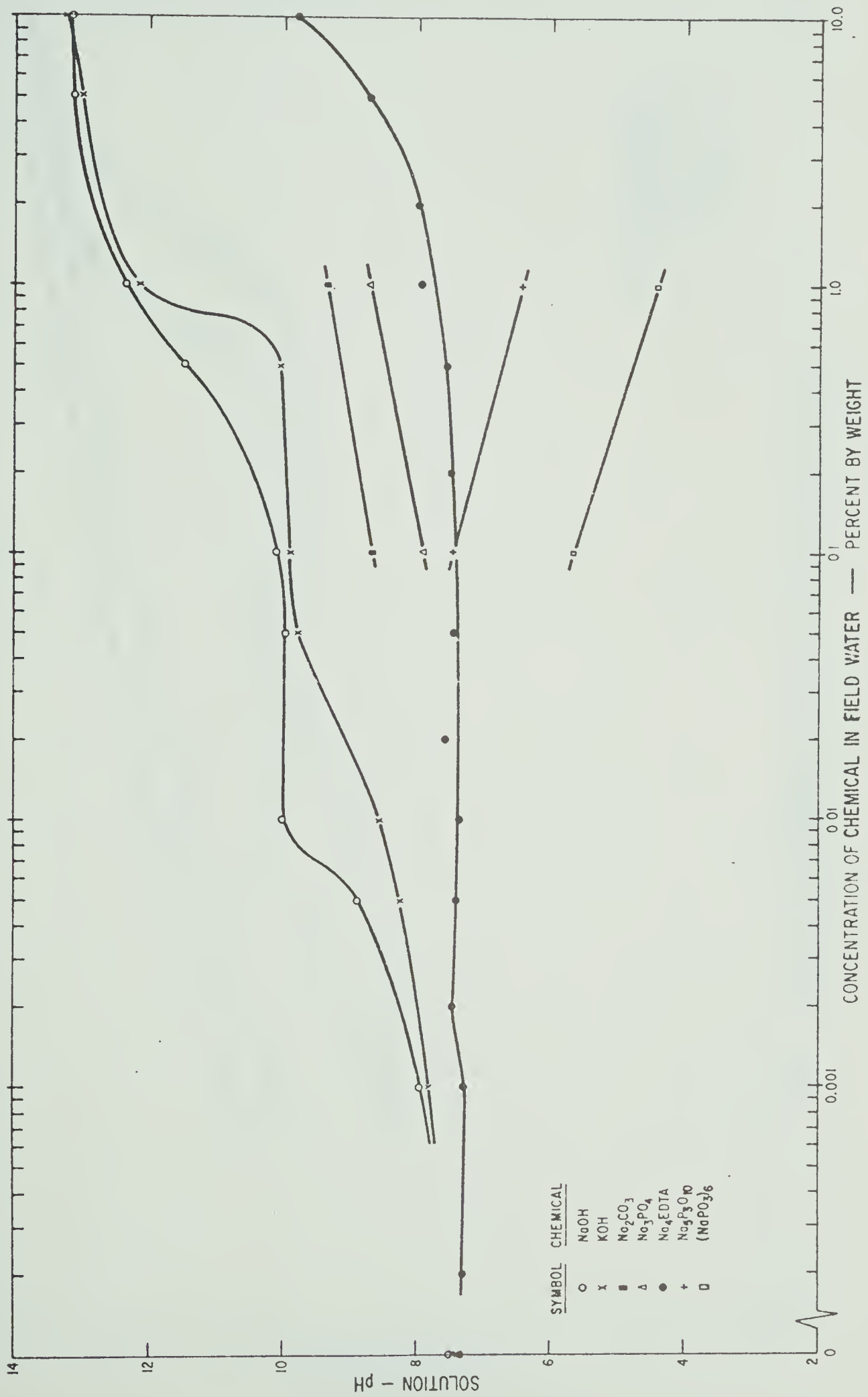


FIG. B-16 - SOLUTION pH MEASUREMENTS OF VARIOUS CHEMICALS IN FIELD WATER

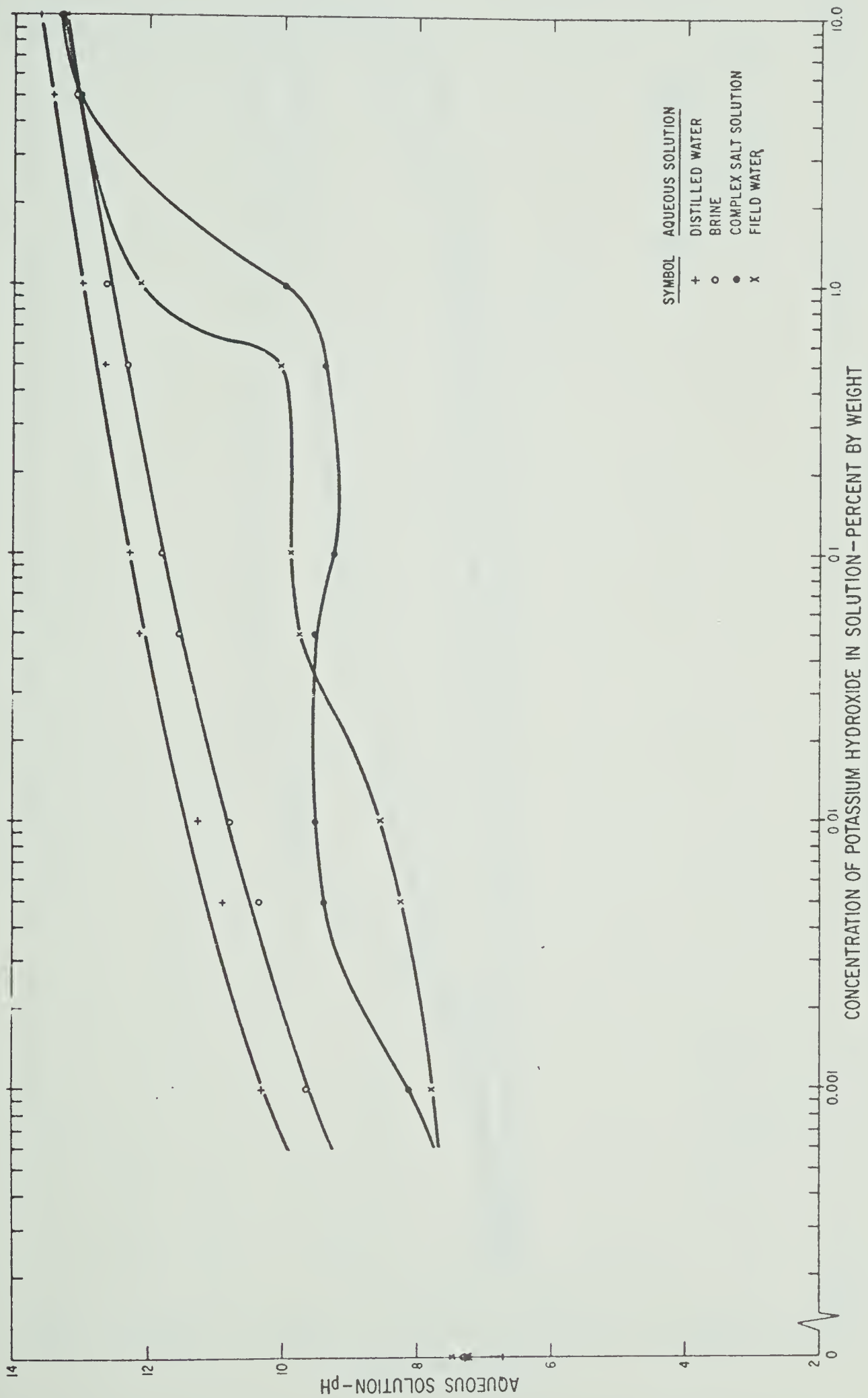


FIG. B - 17 - SOLUTION pH MEASUREMENTS OF POTASSIUM HYDROXIDE IN VARIOUS SOLUTIONS

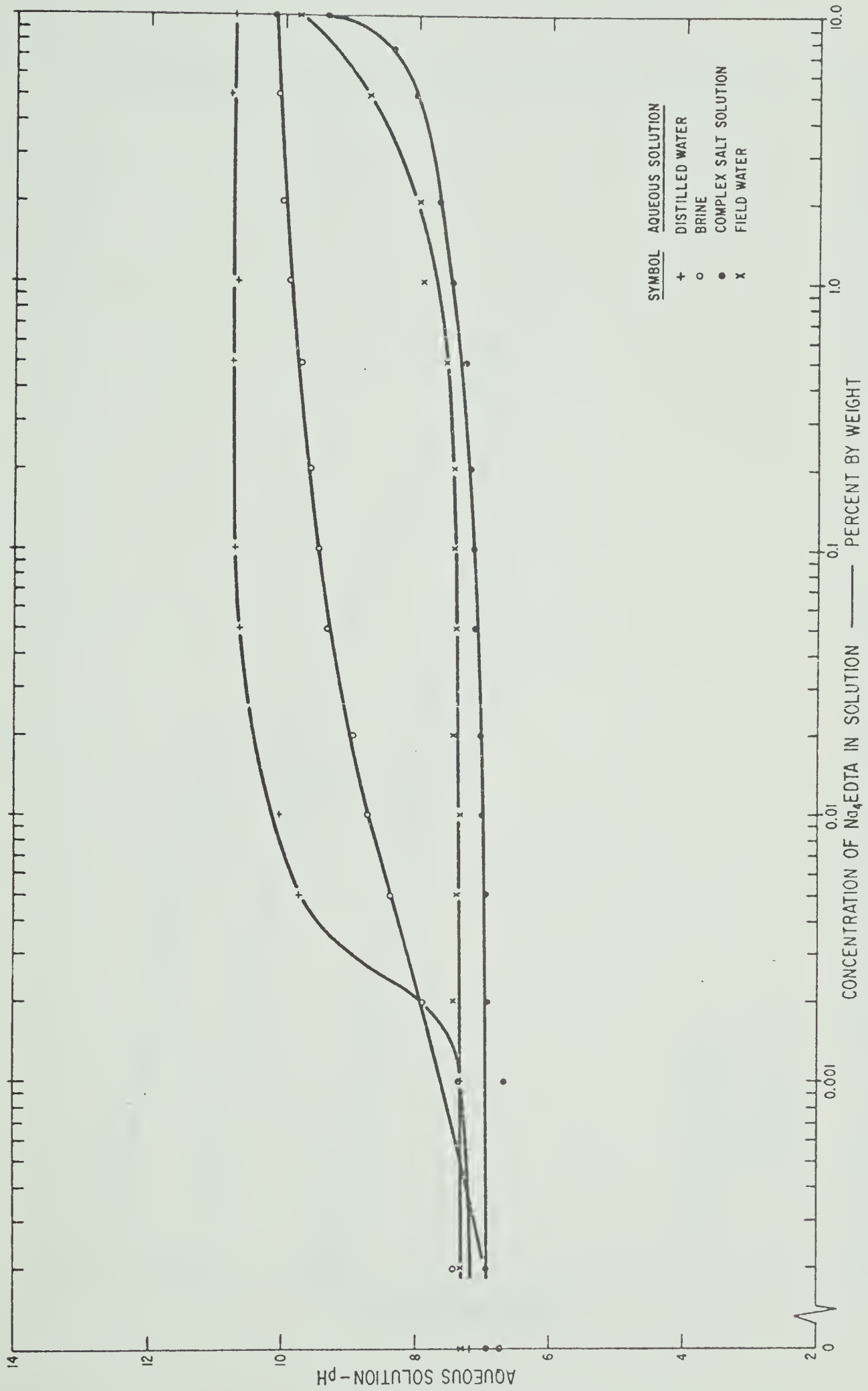


FIG. B-18 - SOLUTION pH MEASUREMENTS OF Na_4EDTA IN VARIOUS SOLUTIONS

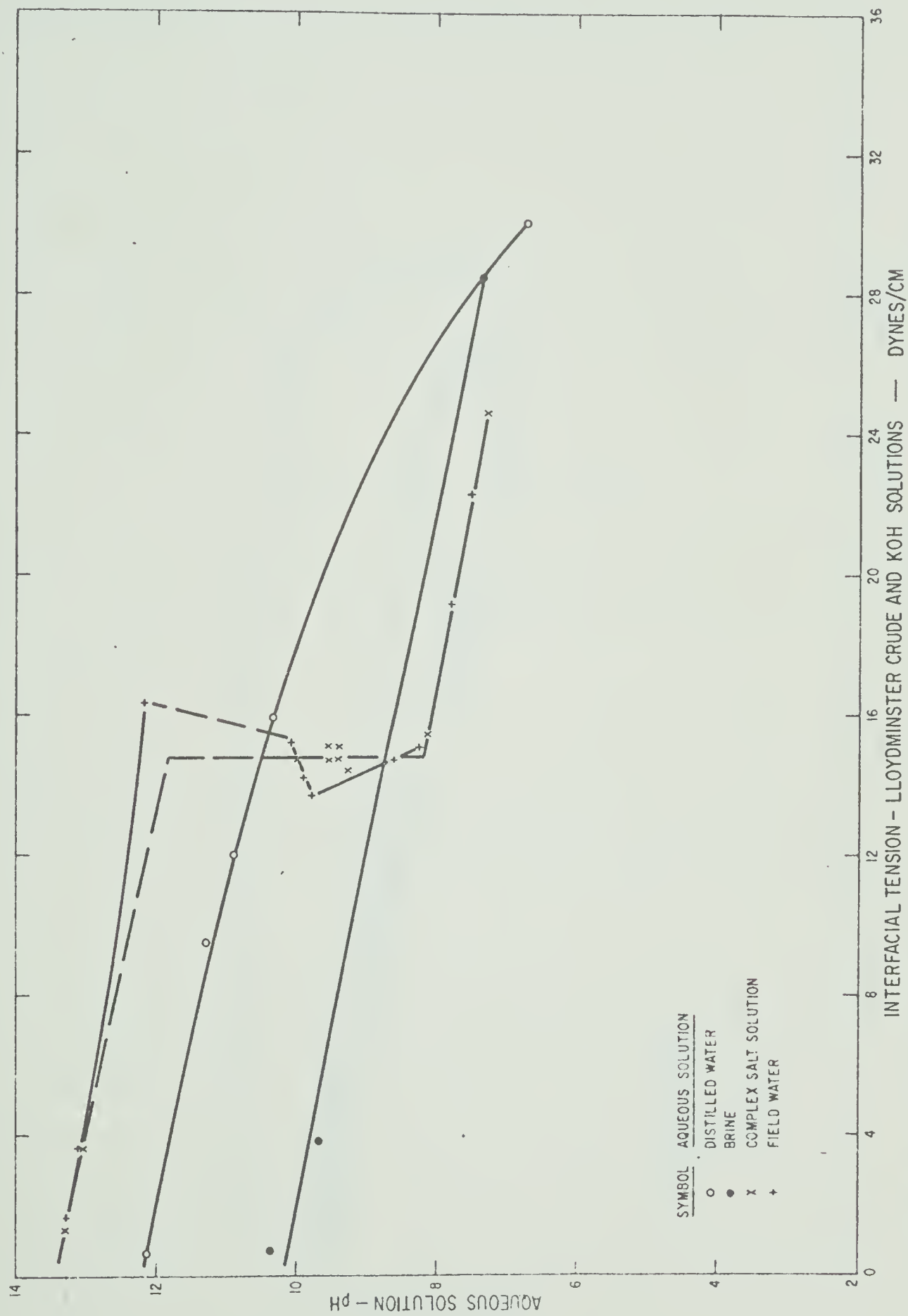


FIG. B-19 - RELATIONSHIP OF AQUEOUS SOLUTION pH AND INTERFACIAL TENSION FOR POTASSIUM HYDROXIDE SOLUTIONS AND LLOYDMINSTER CRUDE OIL

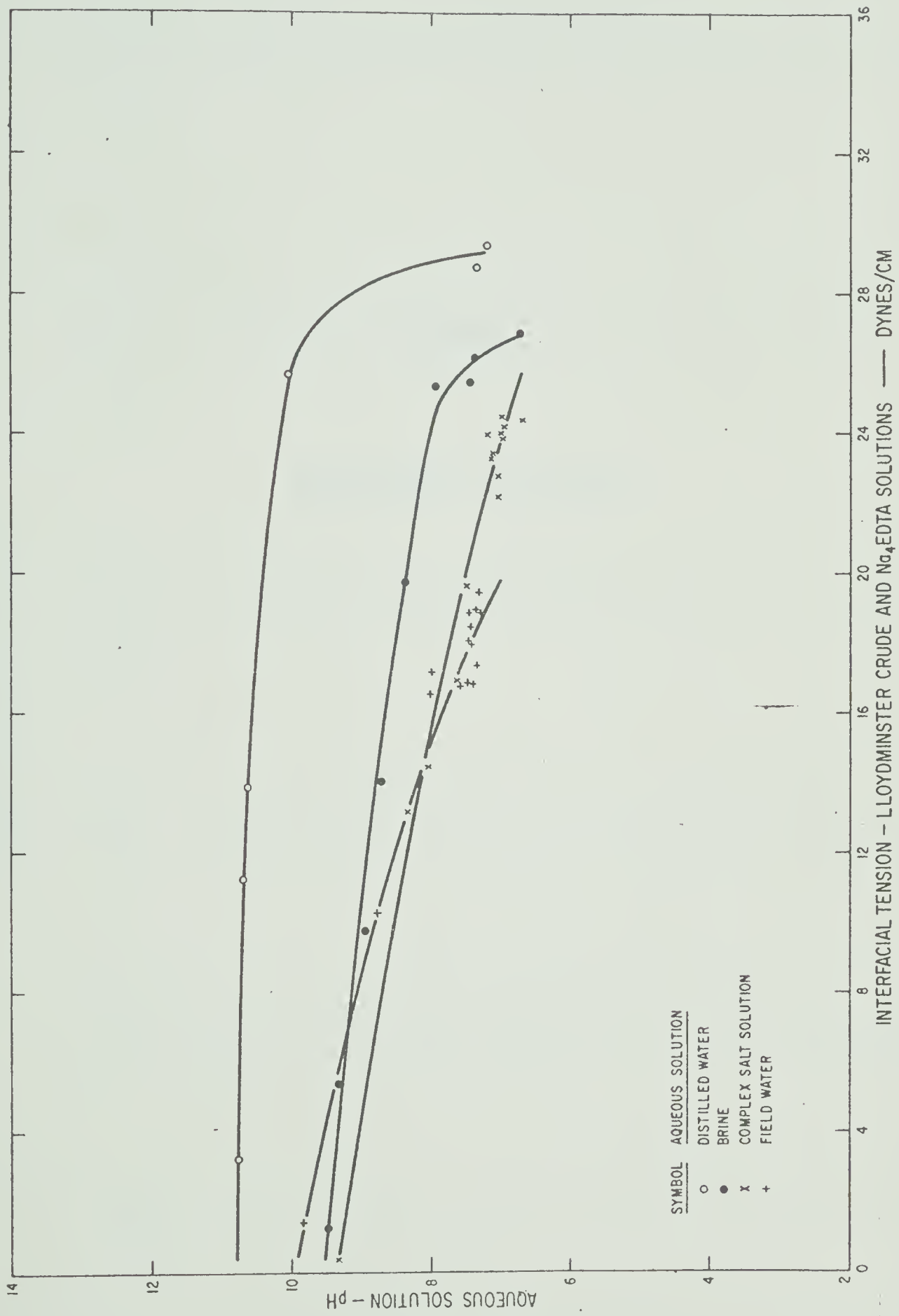


FIG. B-20 - RELATIONSHIP OF AQUEOUS SOLUTION pH AND INTERFACIAL TENSION FOR Na₄EDTA SOLUTIONS AND LLOYDMINSTER CRUDE OIL

APPENDIX C

DISPLACEMENT TEST RESULTS

TABLE C-1

Summary of Displacement Test
Basic Core Properties

Test Number	Sand Number	Core Pore Volume cc	Core Porosity %	Core Brine Permeability Darcies	Initial Water Saturation %	Initial	
						Oil In Place cc	Oil In Place cc
1	1	24.1	41.2	3.27	12.7	21.0	21.0
2	1	23.8	40.8	6.01	13.0	20.7	20.7
3	1	24.1	41.2	3.27	33.9	15.9	15.9
4	1	23.8	40.8	6.01	33.2	15.9	15.9
5	1	24.0	41.0	5.97	10.8	21.4	21.4
6	1	24.1	41.2	7.30	11.2	21.4	21.4
7	1	23.4	40.0	5.87	12.4	20.5	20.5
8	1	23.3	39.9	4.25	12.9	20.3	20.3
9	1	23.2	39.7	4.55	11.6	20.5	20.5
10	1	23.7	40.5	6.48	12.2	20.8	20.8
11	1	23.7	40.5	4.55	11.4	21.0	21.0
12	1	23.8	40.7	7.33	12.2	20.9	20.9
13	1	24.0	41.0	5.95	12.9	20.9	20.9
14	1	24.3	41.5	7.20	11.1	21.6	21.6
15	1	24.3	41.5	7.90	11.1	21.6	21.6
16	1	24.1	41.2	7.19	12.0	21.2	21.2
17	1	23.7	40.5	7.26	11.8	20.9	20.9
18	1	23.8	40.7	7.34	13.0	20.7	20.7
19	1	23.8	40.7	6.30	12.2	20.9	20.9
22	2	25.1	42.9	6.22	11.9	22.1	22.1
23	1	24.1	41.2	7.74	10.8	21.5	21.5
24	2	24.4	41.7	5.07	9.4	22.1	22.1
25	3	25.6	44.8	4.79	13.3	22.2	22.2
26	4	24.0	43.5	6.03	11.3	21.3	21.3
27	1	23.6	40.3	7.57	20.6	18.7	18.7
28	2	24.0	41.0	4.29	15.8	20.2	20.2
29	3	25.8	45.2	5.13	14.3	22.1	22.1
30	4	23.8	42.7	5.81	10.6	21.0	21.0
31	1	24.3	41.5	6.90	14.3	20.7	20.7
32	2	26.5	46.4	5.88	15.8	22.3	22.3

TABLE C-1 (continued)

Test Number	Sand Number	Core Pore Volume cc	Core Porosity %	Core Brine Permeability Darcies	Initial Water Saturation %	Initial Oil In Place	
						cc	
33	3	24.6	42.0	7.25	12.2	21.6	
34	4	23.8	43.3	5.01	13.4	20.6	
35	3	26.9	47.0	5.17	16.0	22.6	
36	1	24.6	42.0	7.13	13.4	21.3	
37	2	25.6	43.8	5.65	11.2	23.0	
38	3	26.8	45.8	3.99	14.9	22.8	
39	1	25.0	42.7	9.39	12.0	22.0	
40	2	25.2	43.1	6.36	11.1	22.4	
41	3	26.2	45.8	4.45	14.5	22.4	
42	1	24.9	42.6	8.44	10.4	22.3	
43	2	24.2	41.4	4.77	10.6	21.6	
44	3	26.1	45.0	2.73	14.2	22.4	
45	1	24.3	41.5	2.65	11.9	21.4	
46	2	25.0	42.8	6.19	11.6	22.1	
47	3	25.8	44.9	7.31	14.7	22.0	
48	1	24.2	41.4	10.74	9.9	21.8	
49	2	24.7	42.2	6.92	11.3	21.9	
50	3	25.8	44.7	3.56	14.7	22.0	
51	1	24.0	41.0	9.57	10.4	21.5	
52	2	24.6	42.0	6.30	9.4	22.3	
53	3	25.7	44.7	3.84	15.2	21.8	
54	1	24.0	41.0	11.30	10.8	21.4	
55	2	24.7	42.2	6.47	9.3	22.4	
56	3	26.5	46.1	4.37	15.1	22.5	
57	1	24.2	41.4	9.01	12.0	21.3	
58	2	24.1	41.2	6.00	10.0	21.7	
59	3	26.8	46.6	5.42	15.3	22.7	
60	1	24.9	42.6	9.25	12.0	21.9	
61	2	24.6	42.1	6.73	9.3	22.3	
62	1	23.8	40.7	9.87	11.4	21.1	
63	1	23.8	40.7	9.08	10.5	21.3	
64	1	23.8	40.7	8.39	10.9	21.2	
65	3	28.1	48.0	5.04	100.0	0.0	
66	2	24.8	42.4	6.55	100.0	0.0	
67	1	24.1	41.2	12.30	100.0	0.0	

TABLE C-2

Summary of Displacement Test
Saturation and Injection Fluid Data

Test Number	Sand Number	Period of		pH	Injection Fluid	
		Water Saturation Days	Oil Saturation Days		Percent Chemical	in Brine
1	1	2	1	7.0		
2	1	1	1	7.0		
3	1	1	1	7.0		
4	1	1	1	7.0		
5	1	0	1	7.0		
6	1	2	1	7.0		
7	1	1	1	7.0		
8	1	1	1	7.0		
9	1	13	1	7.0		
10	1	2	2	12.1	0.1% NaOH	
11	1	5	0	11.1	0.01% NaOH	
12	1	1	1	9.8	0.001% NaOH	
13	1	1	0	10.6	0.005% NaOH	
14	1	63	1	7.0		
15	1	6	13	9.8	0.001% NaOH	
16	1	7	1	9.8	0.001% NaOH	
17	1	1	1	10.3	0.003% NaOH	
18	1	1	24	10.6	0.005% NaOH	
19	1	24	2	10.6	0.005% NaOH	
20	6			7.0		
21	6			7.0		
22	2	10	0	7.0		
23	1	0	0	7.0		
24	2	0	0	7.0		
25	3	0	0	7.0		
26	4	0	0	7.0		
27	1	0	0	12.1	0.1% NaOH	
28	2	0	0	12.1	0.1% NaOH	
29	3	0	0	12.1	0.1% NaOH	
30	4	0	0	12.1	0.1% NaOH	

TABLE C-2 (continued)

Test Number	Sand Number	Period of		Injection Fluid	
		Water Saturation Days	Oil Saturation Days	pH	Percent Chemical in Brine
31	1	0	0	12.81	1.0% NaOH
32	3	0	0	12.81	1.0% NaOH
33	2	0	0	12.81	1.0% NaOH
34	4	0	0	12.81	1.0% NaOH
35	3	1	1	7.0	
36	1	1	1	7.0	
37	2	1	1	7.0	
38	3	1	1	12.6	1.0% KOH
39	1	1	1	12.6	1.0% KOH
40	2	1	1	12.6	1.0% KOH
41	3	1	1	9.9	1.0% Na ₄ EDTA
42	1	1	1	9.9	1.0% Na ₄ EDTA
43	2	1	1	9.9	1.0% Na ₄ EDTA
44	3	1	1	8.4	1.0% Na ₅ P ₃ O ₁₀
45	1	1	1	8.4	1.0% Na ₅ P ₃ O ₁₀
46	2	1	1	8.4	1.0% Na ₅ P ₃ O ₁₀
47	3	1	1	11.1	0.01% NaOH
48	1	1	1	11.1	0.01% NaOH
49	2	1	1	11.1	0.01% NaOH
50	3	1	1	12.1	0.1% NaOH
51	1	1	1	12.1	0.1% NaOH
52	2	1	1	12.1	0.1% NaOH
53	3	1	1	12.8	1.0% NaOH
54	1	1	1	12.8	1.0% NaOH
55	2	1	1	12.8	1.0% NaOH
56	3	1	1	10.6	0.005% NaOH
57	1	1	1	10.6	0.005% NaOH
58	2	1	1	10.6	0.005% NaOH
59	3	1	1	11.2	1.0% Na ₃ PO ₄ • 12 H ₂ O
60	1	1	1	11.2	1.0% Na ₃ PO ₄ • 12 H ₂ O
61	2	1	1	11.2	1.0% Na ₃ PO ₄ • 12 H ₂ O
62	1	1	1	5.5	1.0% (NaPO ₃) ₆
63	1	1	1	10.8	1.0% Na ₂ CO ₃

TABLE C-2 (continued)

<u>Test Number</u>	<u>Sand Number</u>	<u>Period of</u>		<u>Injection Fluid</u>	
		<u>Water Saturation</u>	<u>Oil Saturation</u>	<u>pH</u>	<u>Percent Chemical in Brine</u>
		<u>Days</u>	<u>Days</u>		
64	1	1	1	9.3	1.0% $\text{Na}_4\text{P}_2\text{O}_7$
65	3	1	None	12.8	1.0% NaOH
66	2	1	None	12.8	1.0% NaOH
67	1	1	None	12.8	1.0% NaOH

TABLE C-3

Summary of Displacement Test

Oil Recovery and Saturation Conditions

Test Number	Initial Saturation		Water Breakthrough		Oil Recovery at One Pore		Five Pore	
	Water %	Oil %	PV	IOIP %	Volume Injected		Volumes Injected	
					PV	IOIP %	PV	IOIP %
1	12.7	87.3	0.14	16.3	0.330	37.8	0.547	62.7
2	13.0	87.0	0.105	12.1	0.383	44.0	0.475	54.6
3	33.9	66.1	0.125	18.9	0.387	53.5	0.550	83.2
4	33.2	66.8	0.16	24.0	0.309	46.2	0.453	67.8
5	10.8	89.2	0.12	11.2	0.225	25.2	Test Failed	
6	11.2	88.8	0.125	14.1	0.280	31.6	0.390	43.9
7	12.4	87.6	0.125	14.3	0.288	32.9	0.408	46.6
8	12.9	87.1	0.11	12.6	0.377	43.3	0.428	49.2
9	11.6	88.4	0.10	10.8	0.333	38.5	0.645	73.1
10	12.2	87.8	0.26	29.6	0.505	57.6	0.609	69.3
11	11.4	88.6	0.125	14.1	0.378	42.6	0.568	64.1
12	12.2	87.8	0.12	13.7	0.283	32.2	0.413	47.1
13	12.9	87.1	0.135	15.5	0.390	44.8	0.732	84.0
14	11.1	88.9	0.13	14.6	0.301	33.8	0.400	44.5
15	11.1	88.9	0.12	13.5	0.230	25.9	0.325	36.6
16	12.0	88.0	0.14	15.9	0.282	32.1	0.438	49.8
17	11.8	88.2	0.13	14.7	0.300	34.0	0.383	43.4
18	13.0	87.0	0.12	13.8	0.230	26.4	0.294	33.8
19	12.2	87.2	0.175	20.1	0.264	30.0	0.340	39.0
22	11.9	88.1	0.06	6.8	0.276	31.4	0.667	75.7
23	10.8	89.2	0.10	11.4	0.263	29.5	0.391	43.8
24	9.4	90.6	0.10	11.0	0.227	25.1	0.365	40.3
25	13.3	86.7	0.04	4.6	0.351	40.5	0.841	97.0
26	11.3	88.7	0.05	5.6	0.321	36.2	0.691	77.9
27	20.6	79.4	0.21	26.2	0.506	61.4	0.589	74.2
28	15.8	84.2	0.25	29.7	0.486	57.7	0.508	60.3
29	14.3	85.7	0.20	23.4	0.438	51.2	0.441	51.5
30	10.6	89.4	0.17	19.0	0.515	57.6	0.564	63.1
31	14.8	85.2	0.225	26.4	0.510	57.4	0.617	72.4

TABLE C-4

Displacement Test Recovery Data - Test Number 1

Pore Volume: 24.05 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: Brine Displacement Rate: 30 cc/hr
Sand No: 1 Porosity: 41.2% Brine Permeability: 3.27 Darcies
Initial Water Saturation: 12.7% Initial Oil In Place: 21.0 cc
Sand Density: 2.66 gm/cc $U_O = 940$ cp $U_W = 0.993$ cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W_i	W_i	ΔN_p	N_p			ΔP	$\Delta P / \Delta P_i$
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	90.0	1.0
1.1	0.037	1.1	1.1	0.037	4.3	36.0	0.400
2.7	0.104	1.6	2.7	0.104	11.9	30.0	0.333
4.5	0.179	1.1	3.8	0.150	17.1	19.5	0.217
6.0	0.241	0.5	4.3	0.171	19.5	16.5	0.1833
7.5	0.304	0.3	4.6	0.183	21.0	14.0	0.1555
10.0	0.407	0.5	5.1	0.204	23.3	11.0	0.1222
16.2	0.665	1.2	6.3	0.254	29.0	8.0	0.0890
28.4	1.172	2.7	9.0	0.366	41.9	5.0	0.0555
43.4	1.798	1.6	10.6	0.432	49.5	3.0	0.0333
57.6	2.38	0.9	11.5	0.470	53.8	2.0	0.0222
71.1	2.95	0.6	12.1	0.495	56.7	2.0	0.0667
85.0	3.53	0.5	12.6	0.515	59.1	1.5	0.0139
99.0	4.11	0.4	13.0	0.532	61.0	1.25	0.01111
112.4	4.63	0.2	13.2	0.540	61.9	1.0	0.00889
126.8	5.26	0.2	13.4	0.549	62.9	0.8	0.00833
140.8	5.89	0.3	13.7	0.561	64.3	0.75	0.00833
153.5	6.38	0.1	13.8	0.566	64.8	0.75	0.00778
167.8	6.96	0.1	13.9	0.570	65.3	0.7	0.00778
182.3	7.57	0.2	14.1	0.578	66.2	0.7	0.00555
197.8	8.21	0.3	14.4	0.590	67.6	0.5	0.00555
212.6	8.84	0.2	14.6	0.599	68.6	0.5	0.00555
227.5	9.45	0.1	14.7	0.603	69.1	0.5	0.00555
319.7	13.28	0.7	15.4	0.632	72.4	0.5	0.00555
415.2	17.25	0.5	15.9	0.652	74.8	0.5	0.00555

TABLE C-5

Displacement Test Recovery Data - Test Number 2

Pore Volume: 23.8 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: Brine Displacement Rate: 30 cc/hr
Sand No: 1 Porosity: 40.8% Brine Permeability: 6.01 Darcies
Initial Water Saturation: 13.0% Initial Oil In Place: 20.7 cc
Sand Density: 2.67 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	72.0	1.0
1.3	0.042	1.3	1.3	0.042	4.83	35.5	0.494
3.0	0.118	1.6	2.9	0.113	13.0	26.5	0.368
4.6	0.185	1.2	4.1	0.164	18.9	18.5	0.257
6.3	0.256	1.1	5.2	0.210	24.2	15.3	0.213
9.5	0.391	1.3	6.5	0.264	30.4	11.9	0.166
14.4	0.597	1.5	8.0	0.328	37.7	7.85	0.109
23.9	0.996	1.3	9.3	0.382	43.9	4.8	0.067
35.5	1.482	0.7	10.0	0.412	47.4	3.6	0.050
46.8	1.96	0.3	10.3	0.425	48.9	3.2	0.045
59.1	2.48	0.3	10.6	0.437	50.3	3.0	0.042
71.9	3.01	0.2	10.8	0.446	51.3	2.85	0.040
85.7	3.59	0.2	11.0	0.454	52.2	2.8	0.039
98.4	4.13	0.2	11.2	0.462	53.1	2.8	0.039
112.3	4.72	0.2	11.4	0.471	54.2	2.85	0.040
125.1	5.25	0.6	12.0	0.496	57.0	2.8	0.039
139.3	5.85	0.3	12.3	0.509	58.5	2.9	0.040
148.6	6.24	0.2	12.5	0.517	59.5	2.9	0.040
163.5	6.86	0.2	12.7	0.525	60.4	3.05	0.040
179.0	7.51	0.2	12.9	0.534	61.4	2.65	0.037
192.6	8.09	0.1	13.0	0.538	61.9	2.8	0.039
203.9	8.55	0.1	13.1	0.542	62.3	2.9	0.040
298.3	12.52	1.4	14.5	0.601	69.1	3.85	0.054
382.8	16.08	0.5	15.0	0.622	71.5	4.8	0.067

TABLE C-6

Displacement Test Recovery Data - Test Number 3

Pore Volume: 24.05 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: Brine Displacement Rate: 30 cc/hr
Sand No: 1 Porosity: 41.2% Brine Permeability: 3.27 Darcies
Initial Water Saturation: 33.9% Initial Oil In Place: 15.9 cc
Sand Density: 2.66 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% OIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	94.5	1.0
1.6	0.058	1.6	1.6	0.058	8.8	35.5	0.374
3.4	0.133	1.6	3.2	0.125	18.9	22.0	0.232
5.3	0.212	0.9	4.1	0.162	24.5	17.0	0.179
7.9	0.320	0.8	4.9	0.195	29.5	14.8	0.156
12.7	0.520	1.7	6.6	0.266	40.2	11.0	0.116
22.3	0.920	2.7	9.3	0.379	57.4	6.7	0.071
35.0	1.448	1.1	10.4	0.424	64.1	4.25	0.045
48.6	2.02	0.9	11.3	0.461	69.7	3.35	0.035
60.5	2.51	0.6	11.9	0.486	73.5	3.20	0.034
75.0	3.11	0.6	12.5	0.512	77.5	3.17	0.033
88.8	3.69	0.3	12.8	0.524	79.2	3.45	0.036
102.1	4.24	0.2	13.0	0.532	80.5	3.75	0.040
116.5	4.84	0.4	13.4	0.549	83.0	4.15	0.044
130.3	5.41	0.1	13.5	0.553	83.7	4.52	0.048
142.6	5.92	0.1	13.6	0.560	84.7	4.75	0.050
161.2	6.70	0.3	13.9	0.570	86.2	5.10	0.054
175.0	7.26	0.2	14.1	0.578	87.5	5.18	0.055
187.9	7.81	0.2	14.3	0.586	88.6	5.42	0.057
200.3	8.31	0.1	14.4	0.590	89.3	5.72	0.060
284.6	11.83	0.5	14.9	0.612	92.5	6.50	0.069
379.9	15.80	0.5	15.4	0.632	95.5	7.3	0.077

Remarks: For Test 3 the same core used in Test 1 was re-used without cleaning between runs

TABLE C-7

Displacement Test Recovery Data - Test Number 4

Pore Volume: 23.8 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: Brine Displacement Rate: 30 cc/hr
Sand No: 1 Porosity: 40.8% Brine Permeability: 6.01 Darcies
Initial Water Saturation: 33.2% Initial Oil In Place: 15.9 cc
Sand Density: 2.67 gm/cc $U_o = 940$ cp $U_w = 0.993$ cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W_i	W_i	ΔN_p	N_p			ΔP	$\Delta P/\Delta P_i$
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	98.0	1.0
2.4	0.093	2.4	2.4	0.093	13.9	26.5	0.27
6.5	0.265	2.3	4.7	0.189	28.3	14.5	0.148
13.6	0.563	1.2	5.9	0.240	36.0	8.95	0.091
29.1	1.215	2.3	8.2	0.336	50.3	4.18	0.043
45.4	1.900	1.0	9.2	0.378	56.6	3.09	0.032
59.6	2.49	0.4	9.6	0.395	59.1	2.75	0.028
71.9	3.01	0.4	10.0	0.412	61.6	2.73	0.028
88.0	3.69	0.5	10.5	0.433	64.8	3.10	0.032
102.3	4.29	0.3	10.8	0.445	66.6	3.70	0.038
116.4	4.88	0.1	11.9	0.450	67.4	4.20	0.043
129.3	5.43	0.3	11.2	0.462	69.1	4.32	0.044
143.6	6.03	0.2	11.4	0.471	70.5	4.88	0.050
158.0	6.62	0.2	11.6	0.479	71.7	5.13	0.052
174.5	7.33	0.3	11.9	0.491	73.5	5.52	0.056
187.8	7.88	0.1	12.0	0.496	74.3	5.70	0.058
199.6	8.38	0.1	12.1	0.500	74.9	5.83	0.060
297.1	12.49	0.7	12.8	0.529	79.2	-	-

Remarks: For Test 4 the same core used in Test 2 was re-used without cleaning between runs

TABLE C-8Displacement Test Recovery Data - Test Number 5

Pore Volume: 24.0 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: Brine Displacement Rate: 30 cc/hr
Sand No: 1 Porosity: 41.0% Brine Permeability: 5.97 Darcies
Initial Water Saturation: 10.8% Initial Oil In Place: 21.4 cc
Sand Density: 2.66 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	67.5	1.0
1.2	0.042	1.2	1.2	0.042	4.7	38.5	0.570
2.0	0.075	0.8	2.0	0.075	8.4	31.5	0.466
4.0	0.158	1.2	3.2	0.125	14.0	14.0	0.208
6.4	0.268	0.6	3.8	0.150	16.0	8.5	0.1260
10.1	0.413	0.5	4.3	0.171	19.2	5.8	0.0860
16.4	0.675	0.8	5.1	0.204	22.9	4.0	0.0593
26.3	1.088	0.6	5.7	0.229	25.7	2.8	0.0415

Remarks: Test failed when line developed leak

TABLE C-9

Displacement Test Recovery Data - Test Number 6

Pore Volume: 24.1 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 40.2% Brine Permeability: 7.30 Darcies
Initial Water Saturation: 11.2% Initial Oil In Place: 21.4 cc
Sand Density: 2.68 gm/cc $U_o = 940$ cp $U_w = 0.993$ cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W_i	W_i	ΔN_p	N_p			ΔP	$\Delta P / \Delta P_i$
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	80.0	1.0
0.5	0.012	0.5	0.5	0.012	1.35	50.0	0.625
2.0	0.075	1.5	2.0	0.075	8.45	47.5	0.594
4.3	0.170	1.7	3.7	0.145	16.33	25.0	0.313
8.0	0.324	1.1	4.8	0.191	21.5	14.7	0.184
12.7	0.560	0.8	5.6	0.224	25.2	10.7	0.134
24.9	1.025	1.4	7.0	0.282	31.8	7.7	0.0963
38.8	1.600	0.8	7.8	0.315	35.5	4.6	0.0575
51.9	2.14	0.5	8.3	0.336	37.8	3.6	0.0450
64.9	2.68	0.5	8.8	0.357	40.2	3.2	0.0400
78.7	3.27	0.2	9.0	0.365	41.1	2.7	0.0338
91.8	3.80	0.3	9.3	0.378	42.6	2.5	0.0313
105.6	4.38	0.2	9.5	0.386	43.5	2.3	0.0288
119.6	4.96	0.1	9.6	0.390	44.0	2.2	0.0275
212.6	8.83	1.7	11.3	0.461	52.0	2.2	0.0275
303.4	12.57	1.3	12.6	0.515	58.0	2.8	0.0350
398.4	16.52	1.1	13.7	0.560	63.1	4.2	0.0525
490.2	20.30	0.8	14.5	0.593	66.8	7.5	0.0938

TABLE C-10

Displacement Test Recovery Data - Test Number 7

Pore Volume: 23.4 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 40.0% Brine Permeability: 5.87 Darcies
Initial Water Saturation: 12.4% Initial Oil In Place: 20.5 cc
Sand Density: 2.67 gm/cc $U_o = 940$ cp $U_w = 0.993$ cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil</u> <u>Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	85.8	1.0
1.7	0.064	1.7	1.7	0.064	7.30	44.5	0.519
2.4	0.094	0.7	2.4	0.094	10.73	42.0	0.490
5.9	0.244	1.7	4.1	0.167	19.05	23.5	0.274
10.0	0.419	1.1	5.2	0.214	24.4	16.0	0.1865
14.5	0.611	0.8	6.0	0.256	29.2	11.6	0.1352
18.9	0.800	0.6	6.6	0.274	31.2	9.1	0.1061
29.8	1.265	0.7	7.3	0.304	34.7	5.7	0.0665
43.2	1.840	0.6	7.9	0.329	37.5	4.0	0.0466
58.0	2.47	0.6	8.5	0.355	40.5	3.1	0.0361
71.5	3.05	0.3	8.8	0.368	42.0	2.9	0.0338
85.2	3.63	0.3	9.1	0.380	43.4	2.6	0.0303
99.8	4.26	0.3	9.4	0.393	44.8	2.6	0.0303
113.8	4.85	0.3	9.7	0.406	46.4	2.5	0.0292
127.4	5.44	0.2	9.9	0.415	47.4	2.6	0.0303
217.1	9.28	2.7	12.6	0.530	60.5	3.6	0.0420
313.2	13.38	1.2	13.8	0.581	66.4	4.8	0.0560
402.8	17.21	0.9	14.7	0.620	70.7	5.9	0.0688
490.0	20.95	0.5	15.2	0.641	73.1	3.8	0.0443

TABLE C-11

Displacement Test Recovery Data - Test Number 8

Pore Volume: 23.3 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 39.9% Brine Permeability: 4.25 Darcies
Initial Water Saturation: 12.9% Initial Oil In Place: 20.3 cc
Sand Density: 2.64 gm/cc $U_o = 940$ cp $U_w = 0.993$ cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W_i	W_i	ΔN_p	N_p			ΔP	$\Delta P / \Delta P_i$
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	94.5	1.0
0.0	0.0	-	0.0	0.0	0.0	17.5	-
1.4	0.052	1.4	1.4	0.052	6.0	49.7	0.521
3.5	0.142	1.7	3.1	0.124	14.2	29.0	0.307
5.9	0.245	0.9	4.0	0.163	18.7	19.5	0.206
8.6	0.361	0.4	4.4	0.180	20.7	14.8	0.1566
12.1	0.511	0.9	5.3	0.219	25.1	12.1	0.1280
17.6	0.746	0.7	6.0	0.249	28.6	9.7	0.1026
26.8	1.141	0.9	6.9	0.288	33.1	7.0	0.0741
38.7	1.652	0.6	7.5	0.314	36.0	4.9	0.0519
51.7	2.21	0.5	8.0	0.335	38.4	4.0	0.0423
64.0	2.78	0.4	8.4	0.352	40.4	3.3	0.0349
75.7	3.24	0.5	8.9	0.374	42.9	3.0	0.0317
87.4	3.74	0.4	9.3	0.390	44.8	2.4	0.0254
101.8	4.36	0.5	9.8	0.412	47.3	2.7	0.0286
116.0	4.97	0.3	10.1	0.425	48.8	2.5	0.0264
129.2	5.54	0.2	10.3	0.433	49.7	2.3	0.0243
207.2	8.88	2.1	12.4	0.524	60.1	2.3	0.0243
301.2	12.91	1.9	14.3	0.605	69.5	2.3	0.0243
391.4	16.75	0.9	15.2	0.644	73.9	5.5	0.0582
490.4	21.0	1.0	16.2	0.686	78.8	6.0	0.0635

Remarks: For Test 8 the same core used in Test 6 was re-used with cleaning between runs

TABLE C-12Displacement Test Recovery Data - Test Number 9

Pore Volume: 23.2 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 39.7% Brine Permeability: 4.55 Darcies
Initial Water Saturation: 11.6% Initial Oil In Place: 20.5 cc
Sand Density: 2.63 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	85.1	1.0
1.6	0.060	1.6	1.6	0.060	6.8	47.5	0.558
3.7	0.151	1.2	2.8	0.112	12.7	26.6	0.312
7.4	0.310	1.0	3.8	0.155	17.5	19.0	0.223
13.2	0.560	1.6	5.4	0.224	25.4	14.5	0.1703
23.1	0.988	2.5	7.9	0.332	37.6	8.9	0.1046
33.6	1.440	1.8	9.7	0.410	46.4	6.6	0.0775
46.7	2.02	1.5	11.2	0.475	53.7	5.0	0.0587
60.0	2.58	1.4	12.6	0.535	60.5	4.0	0.0470
77.6	3.34	1.0	13.6	0.578	65.4	3.1	0.0364
92.1	3.97	0.7	14.3	0.608	68.8	2.8	0.0329
104.9	4.51	0.5	14.8	0.630	71.3	2.4	0.0282

Remarks: For Test 9 the same core used in Test 7 was re-used with
 cleaning between runs

TABLE C-13

Displacement Test Recovery Data - Test Number 10

Pore Volume: 23.7 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 0.1% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 40.5% Brine Permeability: 6.48 Darcies
Initial Water Saturation: 12.2% Initial Oil In Place: 20.8 cc
Sand Density: 2.66 gm/cc U_O = 940 cp U_w = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	77.4	1.0
1.2	0.042	1.2	1.2	0.042	4.8	56.8	0.735
4.5	0.182	3.3	4.5	0.182	20.7	43.0	0.556
8.2	0.338	2.4	6.9	0.283	32.2	26.2	0.339
12.5	0.520	1.3	8.2	0.338	38.5	13.9	0.1798
19.1	0.798	2.7	10.9	0.451	51.4	5.9	0.0763
31.1	1.305	2.5	13.4	0.557	63.5	2.8	0.0362
43.6	1.830	0.5	13.9	0.586	66.8	1.6	0.0207
57.9	2.44	0.3	14.2	0.591	67.4	1.7	0.0220
71.9	3.03	0.1	14.3	0.595	67.8	1.5	0.0194
83.0	3.50	0.1	14.4	0.599	68.3	1.5	0.0194
171.2	7.22	0.5	14.9	0.620	70.6	1.7	0.0220
264.2	11.14	0.3	15.2	0.633	72.1	1.4	0.0181
373.7	15.76	0.7	15.9	0.662	75.4	1.6	0.0207
480.2	19.60	0.1	16.0	0.667	76.0	1.5	0.0194

TABLE C-14

Displacement Test Recovery Data - Test Number 11

Pore Volume: 23.7 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 0.01% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 40.5% Brine Permeability: 4.55 Darcies
Initial Water Saturation: 11.4% Initial Oil In Place: 21.0 cc
Sand Density: 2.67 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	79.5	1.0
1.5	0.055	1.5	1.5	0.055	6.2	56.3	0.709
3.4	0.135	1.8	3.3	0.131	14.8	40.5	0.510
6.9	0.283	1.5	4.8	0.194	21.9	23.3	0.293
11.1	0.460	1.0	5.8	0.236	26.6	18.7	0.235
19.9	0.832	2.3	8.1	0.334	37.8	13.6	0.1711
31.6	1.325	3.1	11.2	0.465	52.5	8.7	0.1095
42.8	1.800	0.9	12.1	0.503	56.8	6.9	0.0869
53.3	2.24	0.5	12.6	0.524	59.1	6.6	0.0830
100.0	4.21	0.7	13.3	0.562	63.4	1.5-5.0	0.0630

TABLE C-15

Displacement Test Recovery Data - Test Number 12

Pore Volume: 23.8 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 0.001% NaOH Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 40.7% Brine Permeability: 7.33 Darcies
Initial Water Saturation: 12.2% Initial Oil In Place: 20.9 cc
Sand Density: 2.68 gm/cc $U_o = 940$ cp $U_w = 0.993$ cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W_i	W_i	ΔN_p	N_p			ΔP	$\Delta P/\Delta P_i$
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	76.8	1.0
1.2	0.063	1.7	1.7	0.063	7.2	45.0	0.586
4.9	0.197	2.1	3.8	0.151	17.9	18.0	0.234
9.1	0.374	1.4	5.2	0.210	23.9	12.2	0.159
16.2	0.672	1.0	6.2	0.252	28.7	7.3	0.0950
25.3	1.054	0.8	7.0	0.286	32.6	5.1	0.0664
35.8	1.494	0.7	7.7	0.315	35.9	3.5	0.0456
46.1	1.930	0.5	8.2	0.336	38.3	2.8	0.0365
57.1	2.40	0.4	8.6	0.353	40.6	2.4	0.0313
71.8	3.01	0.5	9.1	0.374	42.6	2.0	0.0260
86.5	3.62	0.4	9.5	0.390	44.4	1.7	0.0212
98.9	4.15	0.2	9.7	0.399	45.5	1.7	0.0212
190.0	7.96	1.3	11.0	0.454	51.7	1.3	0.0169
279.8	11.74	0.8	11.8	0.487	55.5	1.0	0.0130
376.0	15.78	0.4	12.2	0.504	57.3	1.0	0.0130
414.5	17.40	0.3	12.5	0.517	58.9	1.0	0.0130

TABLE C-16

Displacement Test Recovery Data - Test Number 13

Pore Volume: 24.0 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 0.005% NaOH Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 41.0% Brine Permeability: 5.95 Darcies
Initial Water Saturation: 12.9% Initial Oil In Place: 20.9 cc
Sand Density: 2.68 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	Δ N _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	91.7	1.0
1.4	0.050	1.4	1.4	0.050	5.7	57.8	0.631
3.8	0.150	2.1	3.5	0.137	15.7	34.0	0.371
6.1	0.246	0.5	4.0	0.158	18.2	23.2	0.253
9.6	0.392	0.9	4.9	0.196	22.5	18.6	0.203
15.9	0.654	2.0	6.9	0.279	32.0	15.1	0.1648
28.4	1.175	3.8	10.7	0.437	50.2	10.8	0.1178
41.0	1.700	2.5	13.2	0.541	62.1	7.2	0.0785
55.0	2.38	1.8	15.0	0.616	70.8	4.5	0.0491
68.2	2.84	1.0	16.0	0.658	75.5	3.5	0.0382
80.6	3.35	0.7	16.7	0.687	78.9	2.7	0.0295
93.0	3.87	0.4	17.1	0.704	80.8	2.2	0.0240
105.5	4.39	4.9	17.5	0.720	82.6	1.7	0.01855

TABLE C-17

Displacement Test Recovery Data - Test Number 14

Pore Volume: 24.3 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 41.5% Brine Permeability: 7.20 Darcies
Initial Water Saturation: 88.9% Initial Oil In Place: 21.6 cc
Sand Density: 2.71 gm/cc $U_o = 940$ cp $U_w = 0.993$ cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W_i	W_i	ΔN_p	N_p			ΔP	$\Delta P/\Delta P_i$
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	75.1	1.0
2.1	0.078	2.1	2.1	0.078	8.8	46.0	0.613
3.6	0.140	1.3	3.4	0.132	14.9	32.0	0.426
6.7	0.268	1.4	4.8	0.189	21.3	18.0	0.240
11.8	0.478	1.1	5.9	0.235	26.4	11.7	0.156
17.5	0.712	0.8	6.7	0.268	30.2	9.7	0.1292
24.5	1.000	0.8	7.5	0.301	33.9	8.0	0.1066
38.3	1.570	0.7	8.2	0.330	37.2	5.7	0.0759
52.3	2.15	0.4	8.6	0.346	39.0	4.4	0.0586
66.9	2.75	0.4	9.0	0.371	41.7	3.8	0.0506
80.7	3.32	0.3	9.3	0.375	42.2	3.2	0.0426
95.0	3.90	0.3	9.6	0.387	43.5	2.9	0.0386
110.0	4.52	0.2	9.8	0.396	44.6	2.5	0.0333
124.4	5.12	0.3	10.1	0.408	45.9	2.5	0.0333
139.1	5.72	0.2	10.3	0.416	46.8	2.4	0.0320

TABLE C-18

Displacement Test Recovery Data - Test Number 15

Pore Volume: 24.3 cc Temperature: 80° F Oil: Lloydminster Crude

Injected Phase: 0.001% NaOH in Brine Displacement Rate: 40 cc/hr

Sand No: 1 Porosity: 41.5% Brine Permeability: 7.90 Darcies

Initial Water Saturation: 88.9% Initial Oil In Place: 21.6 cc

Sand Density: 2.68 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	72.3	1.0
1.7	0.0618	1.7	1.7	0.0618	6.95	39.0	0.540
3.7	0.144	1.5	3.2	0.1235	13.9	24.5	0.339
6.4	0.255	0.8	4.0	0.1564	17.6	16.2	0.224
10.0	0.403	0.6	4.6	0.1810	20.4	9.4	0.1300
23.3	0.951	1.1	5.7	0.226	25.4	5.2	0.0719
36.4	1.490	0.6	6.3	0.251	28.2	4.0	0.0553
50.6	2.07	0.5	6.8	0.272	30.6	3.1	0.0429
64.2	2.64	0.3	7.1	0.284	32.0	2.8	0.0387
81.8	3.36	0.3	7.4	0.296	33.3	2.2	0.0304
96.6	3.97	0.3	7.7	0.309	34.8	1.8	0.0249
110.9	4.55	0.2	7.9	0.317	35.7	1.7	0.0235
124.6	5.12	0.2	8.1	0.325	36.6	1.2	0.0166
139.3	5.73	0.2	8.3	0.334	37.6	1.7	0.0235
151.5	6.24	0.1	8.4	0.338	38.0	1.6	0.0222

TABLE C-19

Displacement Test Recovery Data - Test Number 16

Pore Volume: 24.1 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 0.001% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 41.2% Brine Permeability: 7.20 Darcies
Initial Water Saturation: 12.0% Initial Oil In Place: 21.2 cc
Sand Density: 2.66 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	Δ N _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	76.8	1.0
1.8	0.0665	1.8	1.8	0.0665	7.55	43.0	0.560
4.5	0.1785	2.1	3.9	0.154	17.5	24.0	0.313
9.4	0.382	1.3	5.2	0.208	23.6	13.1	0.1707
15.7	0.644	1.0	6.2	0.249	28.3	9.7	0.1263
28.1	1.160	1.1	7.3	0.295	33.6	6.5	0.0846
39.7	1.640	0.8	8.1	0.328	37.3	4.5	0.0586
54.4	2.25	0.6	8.7	0.353	40.1	3.3	0.0430
67.8	2.81	0.5	9.2	0.374	42.5	2.5	0.0326
82.2	3.40	0.5	9.7	0.395	44.9	2.3	0.0300
98.0	4.06	0.5	10.2	0.415	47.2	2.0	0.0260
112.3	4.66	0.4	10.6	0.432	49.1	1.7	0.0222
128.0	5.31	0.4	11.0	0.448	51.0	1.7	0.0222
141.9	5.88	0.2	11.2	0.457	52.0	1.6	0.0208

TABLE C-20

Displacement Test Recovery Data - Test Number 17

Pore Volume: 23.7 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 0.003% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 40.5% Brine Permeability: 7.26 Darcies
Initial Water Saturation: 11.8% Initial Oil In Place: 20.9 cc
Sand Density: 2.64 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	76.3	1.0
1.6	0.0591	1.6	1.6	0.0591	6.20	49.3	0.646
3.6	0.1434	1.8	3.4	0.1350	15.3	29.5	0.386
8.6	0.354	1.5	4.9	0.1982	22.5	12.5	0.164
15.3	0.641	1.8	6.7	0.274	31.1	7.6	0.0995
25.7	1.076	0.7	7.4	0.309	34.5	5.3	0.0695
37.5	1.573	0.5	7.9	0.325	36.8	3.8	0.0498
51.3	2.16	0.4	8.3	0.342	38.8	3.0	0.0393
64.4	2.71	0.3	8.6	0.354	40.1	2.3	0.0302
78.7	3.31	0.3	8.9	0.367	41.6	2.0	0.0262
92.1	3.88	0.2	9.1	0.376	42.6	1.7	0.0223
105.9	4.46	0.1	9.2	0.380	43.1	1.4	0.01835
118.9	5.01	0.1	9.3	0.384	43.5	1.3	0.01703
133.5	5.63	0.1	9.4	0.388	44.0	1.2	0.01572
147.1	6.20	0.1	9.5	0.392	44.5	1.2	0.01572

TABLE C-21

Displacement Test Recovery Data - Test Number 18

Pore Volume: 23.8 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 0.005% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 40.7% Brine Permeability: 7.34 Darcies
Initial Water Saturation: 13.0% Initial Oil In Place: 20.7 cc
Sand Density: 2.68 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	65.0	1.0
2.0	0.0156	2.0	2.0	0.0756	8.70	38.0	0.385
4.9	0.1975	1.5	3.5	0.1386	15.92	18.0	0.277
8.6	0.353	0.8	4.3	0.1721	19.8	10.0	0.154
13.8	0.571	0.6	4.9	0.1974	21.7	7.0	0.1177
20.7	0.861	0.5	5.4	0.218	25.1	5.5	0.0846
31.3	1.306	0.5	5.9	0.240	27.5	-	-
42.6	1.780	0.4	6.3	0.256	29.5	3.0	0.0461
57.5	2.41	0.4	6.7	0.273	31.4	2.3	0.0354
72.5	3.04	0.2	6.9	0.282	32.4	1.7	0.0262
86.2	3.61	0.1	7.0	0.286	32.8	1.5	0.0231
100.3	4.20	0.1	7.1	0.290	33.3	1.3	0.0200
114.3	4.79	0.1	7.2	0.294	33.8	1.2	0.1847
128.0	5.36	0.1	7.3	0.298	34.1	1.2	0.1847
139.8	5.86	0.1	7.4	0.302	34.8	1.2	0.1847

TABLE C-22

Displacement Test Recovery Data - Test Number 19

Pore Volume: 23.8 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 0.005% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 40.7% Brine Permeability: 6.30 Darcies
Initial Water Saturation: 12.2% Initial Oil In Place: 20.9 cc
Sand Density: 2.68 gm/cc U_O = 940 cp U_W = 0.933 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
<u>W_i</u>	<u>W_i</u>	<u>ΔN_p</u>	<u>N_p</u>			<u>ΔP</u>	<u>ΔP/ΔP_i</u>
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	86.5	1.0
2.3	0.0882	2.3	2.3	0.0882	10.1	42.0	0.486
6.9	0.282	2.6	4.9	0.1975	22.5	13.5	0.156
15.2	0.630	1.0	5.9	0.240	27.3	6.0	0.0694
27.5	1.147	0.7	6.6	0.269	30.6	3.7	0.0428
41.4	1.730	0.4	7.0	0.286	32.6	2.8	0.0324
54.6	2.28	0.3	7.3	0.298	33.9	2.2	0.0254
71.0	2.98	0.4	7.7	0.315	35.9	2.0	0.0231
87.9	3.68	0.3	8.0	0.328	37.4	1.7	0.01965
102.5	4.30	0.1	8.1	0.332	37.8	1.6	0.01850
116.1	4.87	0.1	8.2	0.336	38.2	1.5	0.01734
129.7	5.45	0.1	8.3	0.340	38.7	1.5	0.01734
143.9	6.04	0.2	8.5	0.349	39.7	1.5	0.01734

TABLE C-23Displacement Test Recovery Data - Test Number 22

Pore Volume: 25.1 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: Brine Displacement Rate: 40 cc/hr
Sand No: 2 Porosity: 42.9% Brine Permeability: 6.22 Darcies
Initial Water Saturation: 11.9% Initial Oil In Place: 22.1 cc
Sand Density: 2.66 gm/cc U_O = 940 cp U_w = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	77.8	1.0
1.9	0.075	1.5	1.5	0.0597	6.79	33.0	0.424
7.4	0.294	1.6	3.1	0.1232	14.02	12.6	0.1620
20.1	0.800	3.0	6.1	0.243	27.6	9.0	0.1157
33.1	1.318	2.0	8.1	0.322	36.6	6.0	0.0771
47.3	1.882	1.9	10.0	0.398	45.3	4.7	0.0604
61.8	2.46	1.5	11.5	0.458	52.1	4.3	0.0553
76.7	3.05	1.6	13.1	0.521	59.4	3.5	0.0450
92.0	3.66	1.3	14.4	0.574	65.2	3.0	0.0386
106.1	4.23	1.0	15.4	0.614	69.7	3.0	0.0386
120.7	4.80	1.0	16.4	0.654	74.3	2.5	0.0322

TABLE C-24Displacement Test Recovery Data - Test Number 23

Pore Volume: 24.1 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 41.2% Brine Permeability: 7.74 Darcies
Initial Water Saturation: 10.8% Initial Oil In Place: 21.5 cc
Sand Density: 2.66 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	76.0	1.0
2.1	0.087	2.1	2.1	0.087	9.8	32.5	0.428
5.3	0.220	1.6	3.7	0.154	17.2	17.0	0.224
14.1	0.585	1.8	5.5	0.228	25.6	8.5	0.1120
24.4	1.013	0.9	6.4	0.264	29.8	4.5	0.0592
38.5	1.600	0.8	7.2	0.299	33.5	3.7	0.0487
51.8	2.15	0.5	7.7	0.320	35.8	3.2	0.0421
65.3	2.71	0.4	8.1	0.336	37.7	2.8	0.0368
78.9	3.28	0.4	8.5	0.353	39.5	2.7	0.0356
92.5	3.84	0.3	8.8	0.366	40.9	2.3	0.0303
106.2	4.41	0.3	9.1	0.378	42.3	2.2	0.0290
118.5	4.92	0.3	9.4	0.390	43.7	2.2	0.0290

TABLE C-25Displacement Test Recovery Data - Test Number 24

Pore Volume: 24.4 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: Brine Displacement Rate: 40 cc/hr
Sand No: 2 Porosity: 41.7% Brine Permeability: 5.07 Darcies
Initial Water Saturation: 9.4% Initial Oil In Place: 22.1 cc
Sand Density: 2.65 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	85.6	1.0
2.1	0.086	2.1	2.1	0.086	9.5	31.5	0.368
5.6	0.230	1.2	3.3	0.135	14.9	14.8	0.1730
12.8	0.525	1.2	4.5	0.184	20.4	7.3	0.0853
19.9	0.815	0.7	5.2	0.213	23.5	5.3	0.0619
33.6	1.378	0.9	6.1	0.250	27.6	3.8	0.0444
47.4	1.941	0.7	6.8	0.278	30.8	3.2	0.0374
61.1	2.50	0.5	7.3	0.299	33.0	3.0	0.0351
74.8	3.06	0.5	7.8	0.320	35.3	2.8	0.0327
88.4	3.62	0.4	8.2	0.336	37.1	2.7	0.0316
102.7	4.21	0.3	8.5	0.348	38.5	2.6	0.0304
116.3	4.77	0.3	8.8	0.361	39.8	2.5	0.0292
119.0	4.88	0.1	8.9	0.365	40.3	2.5	0.0292

TABLE C-26Displacement Test Recovery Data - Test Number 25

Pore Volume: 25.6 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: Brine Displacement Rate: 80 cc/hr
Sand No: 3 Porosity: 44.8% Brine Permeability: 4.79 Darcies
Initial Water Saturation: 13.3% Initial Oil In Place: 22.2 cc
Sand Density: 2.63 gm/cc U_O = 940'cp U_w = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	134.0	1.0
0.5	0.020	0.5	0.5	0.020	2.3	77.5	0.578
5.2	0.203	2.3	2.8	0.109	12.6	34.3	0.256
15.2	0.594	3.5	6.3	0.246	28.4	20.0	0.1492
26.3	1.030	2.8	9.1	0.356	41.0	15.7	0.1172
40.2	1.572	2.8	11.9	0.465	53.6	12.6	0.0940
54.4	2.125	2.2	14.1	0.550	63.5	11.0	0.0821
68.8	2.69	1.9	16.0	0.625	72.1	9.5	0.0709
83.1	3.25	1.5	17.5	0.684	78.9	9.0	0.0672
97.9	3.82	1.5	19.0	0.741	85.6	7.8	0.0582
110.3	4.31	1.0	20.0	0.781	90.1	8.5	0.0635
124.3	4.86	1.3	21.3	0.831	96.0	7.3	0.0545

TABLE C-27

Displacement Test Recovery Data - Test Number 26

Pore Volume: 24.0 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: Brine Displacement Rate: 40 cc/hr
Sand No: 4 Porosity: 43.5% Brine Permeability: 6.03 Darcies
Initial Water Saturation: 11.3% Initial Oil In Place: 21.3 cc
Sand Density: 2.55 gm/cc U_O = 940 cp U_w = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
<u>W_i</u>	<u>W_i</u>	<u>ΔN_p</u>	<u>N_p</u>			<u>ΔP</u>	<u>ΔP/ΔP_i</u>
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	121.1	1.0
2.1	0.088	1.7	1.7	0.071	8.0	77.5	0.640
6.2	0.258	2.0	3.7	0.154	17.4	44.5	0.368
15.3	0.637	2.1	5.8	0.242	27.2	26.7	0.221
25.8	1.075	2.3	8.1	0.337	38.0	20.0	0.165
39.8	1.658	2.5	10.6	0.442	49.0	15.0	0.1239
54.0	2.25	2.4	13.0	0.541	61.0	10.9	0.0900
67.7	2.82	2.0	15.0	0.625	70.5	9.8	0.0809
82.3	3.42	1.9	16.6	0.691	78.0	8.7	0.0719
94.9	3.95	1.6	17.2	0.716	80.7	8.1	0.0669
107.7	4.48	1.3	17.5	0.729	82.2	7.6	0.0627
122.3	5.10	1.3	17.8	0.741	83.6	7.0	0.0578

TABLE C-28

Displacement Test Recovery Data - Test Number 27

Pore Volume: 23.6 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 0.1% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 40.3% Brine Permeability: 7.57 Darcies
Initial Water Saturation: 20.6% Initial Oil In Place: 18.7 cc
Sand Density: 2.685 gm/cc $U_o = 940$ cp $U_w = 0.993$ cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W_i	W_i	ΔN_p	N_p			ΔP	$\Delta P / \Delta P_i$
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	81.5	1.0
2.7	0.114	2.7	2.7	0.114	14.5	47.8	0.587
6.5	0.276	2.8	5.5	0.233	29.6	21.5	0.264
15.7	0.665	3.7	9.2	0.390	49.2	10.0	0.1228
26.6	1.128	3.8	13.0	0.551	69.5	5.0	0.0614
40.7	1.722	0.5	13.5	0.572	72.2	1.7	0.0209
54.2	2.30	0.1	13.6	0.576	72.7	1.5	0.0184
67.9	2.88	0.1	13.7	0.581	73.3	1.5	0.0184
81.7	3.46	0.0	13.7	0.581	73.3	1.6	0.01964
95.9	4.06	0.1	13.8	0.585	73.8	1.2	0.01472
109.6	4.65	0.0	13.8	0.585	73.8	1.2	0.01472
122.1	5.18	0.1	13.9	0.590	74.4	1.2	0.01472

TABLE C-29

Displacement Test Recovery Data - Test Number 28

Pore Volume: 24.0 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 0.1% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 2 Porosity: 41.0% Brine Permeability: 4.29 Darcies
Initial Water Saturation: 15.8% Initial Oil In Place: 20.2 cc
Sand Density: 2.68 gm/cc $U_o = 940$ cp $U_w = 0.993$ cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W_i	W_i	ΔN_p	N_p			ΔP	$\Delta P/\Delta P_i$
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	95.5	1.0
3.6	0.150	3.6	3.6	0.150	17.8	60.6	0.635
8.7	0.362	4.1	7.7	0.321	38.1	40.5	0.424
18.9	0.788	3.8	11.5	0.480	57.0	14.0	0.1468
30.4	1.267	0.4	11.9	0.496	59.0	8.6	0.0901
45.6	1.900	0.2	12.1	0.505	60.0	6.0	0.0629
59.7	2.49	0.1	12.2	0.509	60.5	5.3	0.0555
74.3	3.10	0.0	12.2	0.509	60.5	4.5	0.0471
89.3	3.72	0.0	12.2	0.509	60.5	4.0	0.0419
104.0	4.34	0.0	12.2	0.509	60.5	3.6	0.0377
116.1	4.84	0.0	12.2	0.509	60.5	3.5	0.0357

TABLE C-30Displacement Test Recovery Data - Test Number 29

Pore Volume: 25.8 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 0.1% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 3 Porosity: 45.2% Brine Permeability: 5.13 Darcies
Initial Water Saturation: 14.3% Initial Oil In Place: 22.1 cc
Sand Density: 2.67 gm/cc U_o = 940 cp U_w = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	126.6	1.0
2.0	0.078	2.0	2.0	0.078	9.1	106.0	0.838
5.4	0.209	3.3	5.3	0.205	24.0	90.5	0.715
12.2	0.476	5.0	10.3	0.402	46.6	35.0	0.276
22.4	0.875	0.9	11.2	0.437	50.7	16.0	0.1263
36.5	1.415	0.1	11.3	0.441	51.1	12.0	0.0949
50.5	1.958	0.0	11.3	0.441	51.1	9.5	0.0757
64.8	2.51	0.0	11.3	0.441	51.1	8.1	0.0640
79.0	3.06	0.0	11.3	0.441	51.1	6.9	0.0545
93.7	3.63	0.0	11.3	0.441	51.1	6.2	0.0490
107.5	4.20	0.0	11.3	0.441	51.5	5.5	0.0435

TABLE C-31Displacement Test Recovery Data - Test Number 30

Pore Volume: 23.8 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 0.1% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 4 Porosity: 42.7% Brine Permeability: 5.81 Darcies
Initial Water Saturation: 10.6% Initial Oil In Place: 21.0 cc
Sand Density: 2.56 gm/cc $U_C = 940$ cp $U_{wy} = 0.993$ cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W_i	W_i	ΔN_p	N_p			ΔP	$\Delta P / \Delta P_i$
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	140.6	1.0
4.2	0.179	4.1	4.1	0.175	19.5	111.0	0.790
10.0	0.426	3.8	7.9	0.336	37.6	58.2	0.415
18.3	0.779	3.4	11.3	0.481	52.9	24.5	0.1742
27.0	1.150	1.0	12.3	0.524	58.6	14.0	0.0996
39.1	1.664	0.4	12.7	0.541	60.5	-	-
52.9	2.25	0.1	12.8	0.545	61.0	11.1	0.0790
67.0	2.85	0.1	12.9	0.549	61.5	11.2	0.0796
92.8	3.95	0.2	13.1	0.558	62.4	9.5	0.0672
105.4	4.49	0.1	13.2	0.562	62.9	8.5	0.0605

TABLE C-32Displacement Test Recovery Data - Test Number 31

Pore Volume: 24.3 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 41.5% Brine Permeability: 6.90 Darcies
Initial Water Saturation: 14.8% Initial Oil In Place: 20.7 cc
Sand Density: 2.67 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
<u>W_i</u>	<u>W_i</u>	<u>ΔN_p</u>	<u>N_p</u>			<u>ΔP</u>	<u>ΔP/ΔP_i</u>
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	80.4	1.0
3.0	0.124	3.0	3.0	0.124	14.5	53.5	0.666
6.3	0.269	2.9	5.9	0.243	28.5	29.5	0.367
16.8	0.692	5.5	11.4	0.470	55.1	9.7	0.1208
27.5	1.132	1.3	12.7	0.523	61.4	5.3	0.0660
41.4	1.705	0.8	13.5	0.556	65.3	4.1	0.0510
55.1	2.27	0.5	14.0	0.576	67.7	3.5	0.0435
69.3	2.85	0.4	14.4	0.593	69.6	3.0	0.0373
83.4	3.43	0.2	14.6	0.601	70.5	2.8	0.0348
98.0	4.04	0.2	14.8	0.609	71.5	2.5	0.0311
112.4	4.63	0.1	14.9	0.614	72.0	2.9	0.0361

TABLE C-33

Displacement Test Recovery Data - Test Number 32

Pore Volume: 26.5 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 3 Porosity: 46.4% Brine Permeability: 5.88 Darcies
Initial Water Saturation: 15.8% Initial Oil In Place: 22.3 cc
Sand Density: 2.67 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	120.3	1.0
2.1	0.079	1.9	1.9	0.072	8.6	57.0	0.474
7.4	0.279	3.5	5.4	0.204	24.2	43.5	0.361
15.8	0.596	2.9	8.3	0.313	37.2	24.9	0.207
24.4	0.921	1.1	9.4	0.355	42.2	17.3	0.1437
38.2	1.441	1.7	11.1	0.419	49.8	-	-
53.8	2.03	1.5	12.6	0.476	56.5	9.5	0.0789
67.4	2.54	0.5	13.1	0.495	58.8	8.0	0.0665
81.7	3.08	0.3	13.4	0.506	60.1	6.7	0.0556
94.4	3.56	0.1	13.5	0.510	60.5	6.4	0.0531
106.5	4.02	0.0	13.5	0.510	60.5	6.2	0.0515

TABLE C-34

Displacement Test Recovery Data - Test Number 33

Pore Volume: 24.6 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 2 Porosity: 42.0% Brine Permeability: 7.25 Darcies
Initial Water Saturation: 12.2% Initial Oil In Place: 21.6 cc
Sand Density: 2.67 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
<u>W_i</u>	<u>W_i</u>	<u>ΔN_p</u>	<u>N_p</u>			<u>ΔP</u>	<u>ΔP/ΔP_i</u>
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	76.3	1.0
2.5	0.102	2.5	2.5	0.102	11.6	65.1	0.806
6.1	0.248	2.6	5.1	0.207	23.6	24.0	0.315
15.6	0.635	2.2	7.3	0.297	33.8	13.2	0.1730
28.0	1.139	0.6	7.9	0.321	36.6	10.0	0.1311
40.7	1.655	0.4	8.3	0.338	38.5	7.5	0.0983
54.7	2.22	0.2	8.5	0.346	39.4	6.3	0.0826
67.7	2.75	0.1	8.6	0.350	39.8	5.5	0.0721
81.3	3.30	0.1	8.7	0.354	40.3	5.0	0.0655
94.9	3.84	0.1	8.8	0.358	40.8	4.5	0.0590
109.1	4.44	0.1	8.9	0.362	41.2	4.0	0.0524

TABLE C-35

Displacement Test Recovery Data - Test Number 34

Pore Volume: 23.8 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 4 Porosity: 43.3% Brine Permeability: 5.01 Darcies
Initial Water Saturation: 13.4% Initial Oil In Place: 20.6 cc
Sand Density: 2.56 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	137.1	1.0
4.0	0.168	4.0	4.0	0.168	19.4	134.0	0.976
9.0	0.378	4.5	8.5	0.357	41.2	87.5	0.638
16.0	0.672	3.8	12.3	0.517	58.6	37.0	0.270
29.8	1.252	0.5	12.8	0.538	61.0	22.0	0.1603
43.5	1.828	0.3	13.1	0.551	62.4	17.3	0.1261
57.7	2.425	0.1	13.2	0.555	62.9	14.0	0.1021
70.2	2.95	0.1	13.3	0.559	63.4	12.3	0.0896
83.8	3.52	0.0	13.3	0.559	63.4	11.8	0.0860
97.4	4.09	0.0	13.3	0.559	63.4	11.2	0.0816
111.3	4.68	0.0	13.3	0.559	63.4	10.5	0.0765

TABLE C-36

Displacement Test Recovery Data - Test Number 35

Pore Volume: 26.9 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: Brine Displacement Rate: 40 cc/hr
Sand No: 3 Porosity: 47.0% Brine Permeability: 5.17 Darcies
Initial Water Saturation: 16.0% Initial Oil In Place: 22.6 cc
Sand Density: 2.67 gm/cc $U_o = 940$ cp $U_w = 0.993$ cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W_i	W_i	ΔN_p	N_p			ΔP	$\Delta P / \Delta P_i$
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	110.0	1.0
0.1	0.004	0.1	0.1	0.004	0.4	75.5	0.686
3.0	0.112	1.4	1.5	0.056	6.6	35.0	0.318
11.2	0.416	1.9	3.4	0.134	15.1	18.6	0.1690
19.9	0.740	2.0	5.4	0.201	23.9	13.7	0.1246
33.4	1.242	2.4	7.8	0.290	34.5	14.7	0.1337
47.2	1.754	1.9	9.7	0.361	42.9	7.6	0.0691
61.0	2.27	1.3	11.0	0.409	48.7	6.5	0.0591
74.7	2.78	1.1	12.1	0.450	53.6	6.0	0.0545
88.4	3.29	0.9	13.0	0.484	57.5	5.1	0.0464
102.1	3.80	0.8	13.8	0.513	61.1	5.1	0.0464
116.0	4.31	0.8	14.6	0.543	64.6	4.6	0.0409

TABLE C-37

Displacement Test Recovery Data - Test Number 36

Pore Volume: 24.6 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 42.0% Brine Permeability: 7.13 Darcies
Initial Water Saturation: 13.4% Initial Oil In Place: 21.3 cc
Sand Density: 2.645 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	74.7	1.0
2.3	0.094	2.3	2.3	0.094	10.8	35.0	0.464
5.0	0.203	1.3	3.6	0.146	16.9	14.2	0.1900
11.9	0.484	1.4	5.0	0.203	23.5	10.3	0.1380
19.4	0.789	0.9	5.9	0.240	27.7	7.3	0.0977
33.6	1.365	1.2	7.1	0.288	33.4	5.1	0.0683
47.4	1.927	0.8	7.9	0.321	37.1	3.7	0.0495
61.7	2.51	0.5	8.4	0.342	39.4	3.1	0.0415
75.4	3.06	0.3	8.7	0.354	40.9	2.4	0.0322
89.8	3.65	0.3	9.0	0.366	42.3	2.3	0.0308
103.3	4.20	0.3	9.3	0.378	43.7	2.0	0.0268
117.8	4.79	0.2	9.5	0.386	44.6	1.5	0.0201

TABLE C-38

Displacement Test Recovery Data - Test Number 37

Pore Volume: 25.6 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: Brine Displacement Rate: 40 cc/hr
Sand No: 2 Porosity: 43.8% Brine Permeability: 5.65 Darcies
Initial Water Saturation: 11.2% Initial Oil In Place: 23.0 cc
Sand Density: 2.68 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	74.5	1.0
2.0	0.078	2.0	2.0	0.078	8.7	39.0	0.524
5.1	0.199	1.3	3.3	0.128	14.3	17.7	0.238
13.8	0.539	1.9	5.2	0.203	22.6	8.5	0.1141
22.9	0.395	1.1	6.3	0.246	27.4	5.3	0.0711
36.6	1.430	1.0	7.3	0.285	31.8	3.5	0.0470
50.6	1.978	0.6	7.9	0.308	34.4	2.8	0.0376
64.6	2.52	0.4	8.3	0.324	36.1	2.2	0.0295
78.8	3.08	0.3	8.6	0.336	37.4	2.0	0.0268
92.4	3.61	0.3	8.9	0.348	38.7	1.8	0.0242
106.2	4.15	0.2	9.1	0.355	39.6	1.7	0.0228
120.2	4.70	0.2	9.3	0.363	40.5	1.5	0.0201

TABLE C-39Displacement Test Recovery Data - Test Number 38

Pore Volume: 26.8 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% KOH in Brine Displacement Rate: 40 cc/hr
Sand No: 3 Porosity: 45.8% Brine Permeability: 3.99 Darcies
Initial Water Saturation: 14.9% Initial Oil In Place: 22.8 cc
Sand Density: 2.67 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	124.1	1.0
2.3	0.086	2.1	2.1	0.078	9.2	86.3	0.695
6.0	0.224	2.9	5.0	0.187	21.0	60.0	0.483
15.0	0.560	3.0	8.0	0.298	33.6	28.0	0.226
24.3	0.907	1.1	9.1	0.340	38.2	18.5	0.149
38.3	1.429	1.0	10.1	0.377	44.3	12.2	0.0982
52.5	1.959	0.7	10.8	0.403	47.4	9.4	0.0757
66.2	2.47	0.1	10.9	0.407	47.8	8.1	0.0652
80.6	3.01	0.1	11.0	0.410	48.3	7.0	0.0564
94.4	3.52	0.1	11.1	0.415	48.7	6.6	0.0531
107.1	4.00	0.1	11.2	0.418	49.1	6.2	0.0499
120.4	4.50	0.0	11.2	0.418	49.1	5.8	0.0467

TABLE C-40Displacement Test Recovery Data - Test Number 39

Pore Volume: 25.0 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% KOH in Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 42.7% Brine Permeability: 9.39 Darcies
Initial Water Saturation: 12.0% Initial Oil In Place: 22 0 cc
Sand Density: 2.69 gm/cc U_o = 940 cp U_w = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	48.9	1.0
3.3	0.132	2.9	2.9	0.116	13.2	28.5	0.583
7.8	0.312	3.0	5.9	0.236	26.8	18.1	0.370
18.2	0.728	6.0	11.9	0.476	54.1	15.1	0.309
29.0	1.160	4.7	16.6	0.664	75.5	9.0	0.1840
43.4	1.736	1.9	18.5	0.740	84.1	2.4	0.0491
57.1	2.28	0.3	18.8	0.752	85.5	1.9	0.0389
71.4	2.86	0.1	18.9	0.756	86.0	1.8	0.0368
85.1	3.40	0.1	19.0	0.760	86.4	1.5	0.0307
98.7	3.95	0.1	19.1	0.764	86.9	1.5	0.0307
112.4	4.50	0.0	19.1	0.764	86.9	1.4	0.0286
124.9	5.00	0.0	19.1	0.764	86.9	1.4	0.0286

TABLE C-41

Displacement Test Recovery Data - Test Number 40

Pore Volume: 25.2 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% KOH in Brine Displacement Rate: 40 cc/hr
Sand No: 2 Porosity: 43.1% Brine Permeability: 6.36 Darcies
Initial Water Saturation: 11.1% Initial Oil In Place: 22.4 cc
Sand Density: 2.67 gm/cc $U_o = 940$ cp $U_w = 0.993$ cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W_i	W_i	ΔN_p	N_p			ΔP	$\Delta P / \Delta P_i$
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	82.7	1.0
3.7	0.147	3.7	3.7	0.147	16.5	55.0	0.665
7.6	0.302	2.9	6.6	0.262	29.5	30.5	0.369
16.1	0.639	3.0	9.6	0.381	42.8	26.5	0.320
28.0	1.112	1.8	11.4	0.452	50.9	27.5	0.332
41.1	1.632	1.2	12.6	0.500	56.3	61.0	0.737
55.5	2.20	0.4	13.0	0.516	58.0	29.0	0.351
71.5	2.84	0.3	13.3	0.528	59.4	-	-

Remarks: Test failed when line developed leak.

TABLE C-42

Displacement Test Recovery Data - Test Number 41

Pore Volume: 26.2 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% Na₄EDTA in Brine Displacement Rate: 40 cc/hr
Sand No: 3 Porosity: 45.8% Brine Permeability: 4.45 Darcies
Initial Water Saturation: 14.5% Initial Oil In Place: 22.4 cc
Sand Density: 2.67 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	143.9	1.0
2.9	0.107	2.2	2.2	0.084	9.8	83.7	0.582
7.2	0.275	3.0	5.2	0.199	23.2	81.2	0.565
16.3	0.612	5.0	10.2	0.389	45.5	43.8	0.304
26.5	1.012	3.6	13.8	0.526	61.6	22.2	0.1542
40.3	1.539	1.6	15.4	0.588	68.7	11.2	0.0778
53.0	2.02	0.6	16.0	0.611	71.4	8.3	0.0577
67.6	2.58	0.4	16.4	0.626	73.2	7.2	0.0500
81.3	3.10	0.3	16.7	0.637	74.5	6.5	0.0452
95.3	3.64	0.2	16.9	0.645	75.5	6.3	0.0438
108.9	4.16	0.3	17.2	0.656	76.8	6.0	0.0417

TABLE C-43Displacement Test Recovery Data - Test Number 42

Pore Volume: 24.9 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% Na₄EDTA in Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 42.6% Brine Permeability: 8.44 Darcies
Initial Water Saturation: 10.4% Initial Oil In Place: 22.3 cc
Sand Density: 2.67 gm/cc U_o = 940 cp U_w = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	77.4	1.0
3.5	0.141	3.3	3.3	0.133	14.8	29.5	0.381
8.2	0.330	2.4	5.7	0.229	25.6	19.9	0.257
16.7	0.671	5.0	10.7	0.430	48.0	15.1	0.195
26.8	1.069	4.1	14.8	0.595	66.4	7.1	0.0917
41.6	1.672	2.1	16.9	0.679	75.8	3.0	0.0388
56.0	2.25	0.6	17.5	0.703	78.5	2.5	0.0323
70.4	2.83	0.3	17.8	0.715	79.8	1.7	0.0220
84.2	3.38	0.2	18.0	0.723	80.7	1.5	0.0194
97.9	3.93	0.2	18.2	0.731	81.6	1.5	0.0194
111.9	4.49	0.2	18.4	0.739	82.5	1.5	0.0194

TABLE C-44

Displacement Test Recovery Data - Test Number 43

Pore Volume: 24.2 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% Na₄EDTA in Brine Displacement Rate: 40 cc/hr
Sand No: 2 Porosity: 41.4% Brine Permeability: 4.77 Darcies
Initial Water Saturation: 10.6% Initial Oil In Place: 21.6 cc
Sand Density: 2.66 gm/cc U_o = 940 cp U_w = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	88.0	1.0
3.2	0.130	3.2	3.2	0.130	14.8	62.0	0.705
7.2	0.293	2.5	5.7	0.232	26.4	42.0	0.477
14.9	0.616	3.6	9.3	0.378	43.1	24.8	0.282
24.0	0.993	1.6	10.9	0.451	50.5	15.6	0.177
38.5	1.566	1.3	12.2	0.505	56.5	9.5	0.1080
52.7	2.14	0.4	12.6	0.521	58.3	7.0	0.0795
67.2	2.73	0.1	12.7	0.525	58.8	6.1	0.0694
80.8	3.29	0.1	12.8	0.529	59.3	5.0	0.0569
94.0	3.82	0.1	12.9	0.534	59.7	4.6	0.0511
108.8	4.50	0.1	13.0	0.538	60.2	4.3	0.0489

TABLE C-45

Displacement Test Recovery Data - Test Number 44

Pore Volume: 26.1 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% Na₅P₃O₁₀ in Brine Displacement Rate: 40 cc/hr
Sand No: 3 Porosity: 45.0% Brine Permeability: 2.725 Darcies
Initial Water Saturation: 14.2% Initial Oil In Place: 22.4 cc
Sand Density: 2.67 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	189.8	1.0
1.3	0.050	0.9	0.9	0.035	4.0	76.5	0.403
5.7	0.218	1.9	2.8	0.107	12.5	47.0	0.248
15.9	0.610	2.3	5.1	0.196	22.8	19.0	0.1002
25.9	0.993	1.4	6.5	0.249	29.0	15.0	0.0791
40.0	1.532	2.0	8.5	0.326	38.0	12.1	0.0638
53.9	2.07	1.5	10.0	0.383	44.6	9.9	0.0522
67.8	2.60	1.3	11.3	0.433	50.5	8.7	0.0459
81.5	3.12	1.2	12.5	0.479	55.8	7.7	0.0406
95.4	3.66	0.9	13.4	0.514	59.9	7.0	0.0369
109.0	4.18	0.7	14.1	0.541	63.0	6.6	0.0348
124.0	4.75	0.7	14.8	0.567	66.1	6.2	0.0327

TABLE C-46

Displacement Test Recovery Data - Test Number 45

Pore Volume: 24.3 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% Na₅P₃O₁₀ in Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 41.5% Brine Permeability: 9.77 Darcies
Initial Water Saturation: 11.9% Initial Oil In Place: 21.4 cc
Sand Density: 2.65 gm/cc U_O = 940 cp U_w = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	51.2	1.0
2.2	0.091	2.2	2.2	0.091	10.3	30.6	0.598
6.0	0.247	2.1	4.3	0.177	20.1	15.6	0.305
14.9	0.614	1.5	5.8	0.239	27.1	5.0	0.0976
24.2	0.996	1.1	6.9	0.284	32.2	3.4	0.0664
38.6	1.589	1.7	8.6	0.354	40.2	2.7	0.0527
53.0	2.18	1.4	10.0	0.411	46.7	2.3	0.0449
67.2	2.76	1.1	11.1	0.457	51.9	2.5	0.0488
82.2	3.38	0.9	12.0	0.494	56.1	1.9	0.0371
95.6	3.94	0.9	12.9	0.531	60.3	2.4	0.0469
109.8	4.52	0.7	13.6	0.560	63.6	2.2	0.0430
124.7	5.13	0.7	14.3	0.588	66.9	2.6	0.0508

TABLE C-47

Displacement Test Recovery Data - Test Number 46

Pore Volume: 25.0 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% Na₅P₃O₁₀ in Brine Displacement Rate: 40 cc/hr
Sand No: 2 Porosity: 42.8% Brine Permeability: 6.19 Darcies
Initial Water Saturation: 11.6% Initial Oil In Place: 22.1 cc
Sand Density: 2.65 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	74.4	1.0
1.6	0.064	1.5	1.5	0.060	6.8	31.0	0.417
4.2	0.168	0.9	2.4	0.096	10.9	20.7	0.278
14.1	0.564	2.4	4.8	0.192	21.7	8.1	0.1090
25.4	1.016	1.5	6.3	0.252	28.5	5.1	0.0686
39.7	1.569	1.4	7.7	0.308	34.8	3.6	0.0484
54.7	2.19	0.8	8.5	0.340	38.4	3.0	0.0403
68.5	2.74	0.6	9.1	0.364	41.2	2.6	0.0350
82.2	3.29	0.5	9.6	0.384	43.4	2.3	0.0309
95.9	3.84	0.3	9.9	0.396	44.8	2.0	0.0269
109.5	4.38	0.2	10.1	0.404	45.7	2.0	0.0269
123.3	4.94	0.1	10.2	0.408	46.2	2.0	0.0269

TABLE C-48

Displacement Test Recovery Data - Test Number 47

Pore Volume: 25.8 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 0.01% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 3 Porosity: 44.9% Brine Permeability: 7.31 Darcies
Initial Water Saturation: 14.7% Initial Oil In Place: 22.0 cc
Sand Density: 2.65 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	Δ N _p	N _p			Δ P	Δ P/Δ P _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	170.7	1.0
1.0	0.039	0.9	0.9	0.035	4.1	102.5	0.601
4.1	0.159	1.4	2.3	0.089	10.5	49.0	0.287
14.2	0.550	2.4	4.7	0.182	21.4	24.2	0.1418
25.6	0.992	2.3	7.0	0.272	21.8	16.6	0.0972
39.8	1.543	2.2	9.2	0.357	41.8	13.5	0.0791
53.4	2.07	1.7	10.9	0.422	49.5	11.5	0.0664
67.6	2.62	1.5	12.4	0.481	56.4	9.8	0.0574
81.5	3.16	1.5	13.9	0.539	63.2	9.7	0.0568
96.6	3.75	1.3	15.2	0.589	69.1	8.1	0.0475
110.8	4.30	1.2	16.4	0.636	74.5	7.9	0.0462

TABLE C-49

Displacement Test Recovery Data - Test Number 48

Pore Volume: 24.2 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 0.01% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 41.4% Brine Permeability: 10.74 Darcies
Initial Water Saturation: 9.9% Initial Oil In Place: 21.8 cc
Sand Density: 2.67 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil</u> <u>Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	58.0	1.0
3.0	0.124	3.0	3.0	0.124	13.8	35.0	0.604
6.1	0.252	1.6	4.6	0.190	21.1	17.2	0.297
15.5	0.641	1.7	6.3	0.260	28.9	7.7	0.1328
26.0	1.074	0.9	7.2	0.298	33.0	5.7	0.0583
39.9	1.649	1.1	8.3	0.343	38.1	4.1	0.0707
53.8	2.22	0.6	8.9	0.368	40.8	3.2	0.0552
67.9	2.81	0.3	9.2	0.380	42.2	2.2	0.0379
82.0	3.39	0.3	9.5	0.393	43.6	2.0	0.0345
96.0	3.97	0.2	9.7	0.401	44.5	1.7	0.0293
110.3	4.56	0.1	9.8	0.405	45.0	1.3	0.0224
124.7	5.15	0.1	9.9	0.409	45.5	2.0	0.0345

TABLE C-50

Displacement Test Recovery Data - Test Number 49

Pore Volume: 24.7 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 0.01% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 2 Porosity: 42.2% Brine Permeability: 6.92 Darcies
Initial Water Saturation: 11.3% Initial Oil In Place: 21.9 cc
Sand Density: 2.67 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	78.1	1.0
2.3	0.093	2.2	2.2	0.089	10.1	39.0	0.499
5.5	0.223	1.5	3.7	0.150	16.9	20.0	0.256
15.0	0.608	1.9	5.6	0.227	25.6	8.9	0.1140
25.6	1.037	1.3	6.9	0.280	31.5	5.5	0.0705
40.1	1.624	1.4	8.3	0.336	37.9	4.0	0.0512
53.8	2.18	1.1	9.4	0.381	42.9	3.5	0.0448
67.4	2.73	1.0	10.4	0.421	47.5	3.2	0.0410
81.0	3.28	0.8	11.2	0.454	51.1	3.2	0.0410
94.3	3.82	0.8	12.0	0.486	54.8	2.7	0.0346
108.2	4.38	0.8	12.8	0.518	58.5	2.8	0.0358

TABLE C-51

Displacement Test Recovery Data - Test Number 50

Pore Volume: 25.8 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 0.1% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 3 Porosity: 44.7% Brine Permeability: 3.56 Darcies
Initial Water Saturation: 14.7% Initial Oil In Place: 22.0 cc
Sand Density: 2.675 gm/cc $\underline{U}_O = 940$ cp $\underline{U}_W = 0.993$ cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W_i	W_i	ΔN_p	N_p			ΔP	$\Delta P/\Delta P_i$
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	174.0	1.0
2.8	0.109	2.8	2.8	0.109	12.7	152.5	0.876
6.6	0.256	2.9	5.7	0.211	25.9	100.0	0.575
15.5	0.601	4.3	10.0	0.388	45.5	43.2	0.248
26.3	1.020	4.1	14.1	0.546	64.1	24.0	0.1380
40.3	1.562	1.1	15.2	0.590	69.1	15.2	0.0874
54.2	2.10	0.1	15.3	0.593	69.5	10.0	0.0575
68.2	2.64	0.0	15.3	0.593	69.5	8.0	0.0460
81.8	3.17	0.0	15.3	0.593	69.5	6.9	0.0397
86.0	3.72	0.0	15.3	0.593	69.5	6.0	0.0345
112.0	4.35	0.0	15.3	0.593	69.5	5.1	0.0293

TABLE C-52

Displacement Test Recovery Data - Test Number 51

Pore Volume: 24.0 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 0.1% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 41.0% Brine Permeability: 9.57 Darcies
Initial Water Saturation: 10.4% Initial Oil In Place: 21.5 cc
Sand Density: 2.66 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
<u>W_i</u>	<u>W_i</u>	<u>ΔN_p</u>	<u>N_p</u>			<u>ΔP</u>	<u>ΔP/ΔP_i</u>
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	69.1	1.0
3.7	0.154	3.7	3.7	0.154	17.2	43.0	0.622
8.3	0.346	2.9	6.6	0.275	30.7	21.5	0.311
19.6	0.817	4.7	11.3	0.471	51.4	8.5	0.1232
30.8	1.283	2.1	13.4	0.559	60.9	3.3	0.0478
45.0	1.875	0.4	13.8	0.575	62.7	1.4	0.0203
58.7	2.45	0.2	14.0	0.584	63.6	1.2	0.01738
72.3	3.01	0.1	14.1	0.588	64.1	1.0	0.01448
86.0	3.58	0.1	14.2	0.592	64.5	1.0	0.01448
99.6	4.15	0.1	14.3	0.596	65.0	0.9	0.01304
114.1	4.76	0.0	14.3	0.596	65.0	0.9	0.01304

TABLE C-53

Displacement Test Recovery Data - Test Number 52

Pore Volume: 24.6 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 0.1% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 2 Porosity: 42.0% Brine Permeability: 6.30 Darcies
Initial Water Saturation: 9.4% Initial Oil In Place: 22.3 cc
Sand Density: 2.655 gm/cc $\underline{U}_O = 940$ cp $\underline{U}_W = 0.993$ cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W_i	W_i	ΔN_p	N_p			ΔP	$\Delta P / \Delta P_i$
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	94.8	1.0
3.4	0.138	3.4	3.4	0.138	15.3	65.1	0.687
6.9	0.281	3.2	6.6	0.268	29.6	40.0	0.422
16.7	0.679	3.4	10.0	0.407	44.9	12.8	0.1350
26.3	1.070	1.1	11.1	0.451	49.8	9.7	0.1023
40.1	1.631	0.3	11.4	0.464	51.1	6.4	0.0675
53.7	2.18	0.2	11.6	0.472	52.0	5.5	0.0580
67.5	2.74	0.1	11.7	0.476	52.5	3.5	0.0369
82.8	3.37	0.1	11.8	0.480	52.9	2.8	0.0295
96.2	3.91	0.0	11.8	0.480	52.9	2.6	0.0274
110.2	4.48	0.0	11.8	0.480	52.9	2.3	0.0243

TABLE C-54Displacement Test Recovery Data - Test Number 53

Pore Volume: 25.7 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 3 Porosity: 44.7% Brine Permeability: 3.84 Darcies
Initial Water Saturation: 15.2% Initial Oil In Place: 21.8 cc
Sand Density: 2.65 gm/cc $U_O = 940$ cp $U_W = 0.993$ cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W_i	W_i	ΔN_p	N_p			ΔP	$\Delta P / \Delta P_i$
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	201.0	1.0
2.1	0.082	2.1	2.1	0.082	9.6	120.5	0.600
5.7	0.222	1.8	3.9	0.152	17.9	85.2	0.424
15.5	0.604	3.9	7.8	0.304	35.8	43.5	0.216
25.9	1.008	2.7	10.5	0.409	48.2	35.3	0.1756
39.8	1.550	2.6	13.1	0.510	60.1	25.0	0.1243
53.6	2.09	1.7	14.8	0.516	67.9	19.3	0.0960
67.4	2.69	0.9	15.7	0.611	72.1	15.0	0.0746
81.2	3.16	0.4	16.1	0.627	73.9	12.5	0.0622
94.7	3.69	0.2	16.3	0.635	74.8	10.7	0.0532
109.0	4.24	0.1	16.4	0.638	75.3	9.6	0.0478
123.4	4.80	0.1	16.5	0.642	75.7	9.3	0.0462

TABLE C-55

Displacement Test Recovery Data - Test Number 54

Pore Volume: 24.0 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 41.0% Brine Permeability: 11.30 Darcies
Initial Water Saturation: 10.8% Initial Oil In Place: 21.4 cc
Sand Density: 2.66 gm/cc $U_o = 940$ cp $U_w = 0.993$ cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W_i	W_i	ΔN_p	N_p			ΔP	$\Delta P/\Delta P_i$
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	61.1	1.0
3.1	0.129	3.1	3.1	0.129	14.5	43.0	0.704
7.4	0.308	3.4	6.5	0.271	30.4	20.0	0.327
16.8	0.700	3.4	9.9	0.412	46.3	7.2	0.1178
26.6	1.108	1.3	11.2	0.467	52.4	5.0	0.0818
40.0	1.667	0.8	12.0	0.500	56.1	3.4	0.0556
53.8	2.24	0.5	12.5	0.521	58.5	2.7	0.0442
68.8	2.87	0.4	12.9	0.538	60.3	2.3	0.0376
82.4	3.43	0.2	13.1	0.546	61.2	2.1	0.0344
96.0	4.00	0.1	13.2	0.550	61.7	1.9	0.0311
109.9	4.58	0.1	13.3	0.554	62.1	1.8	0.0294

TABLE C-56Displacement Test Recovery Data - Test Number 55

Pore Volume: 24.7 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 2 Porosity: 42.2% Brine Permeability: 6.47 Darcies
Initial Water Saturation: 9.3% Initial Oil In Place: 22.4 cc
Sand Density: 2.66 gm/cc U_O = 940 cp U_w = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	104.0	1.0
3.1	0.126	3.1	3.1	0.126	13.8	65.0	0.625
6.5	0.263	2.9	6.0	0.243	26.8	36.5	0.351
14.5	0.587	3.5	9.5	0.385	42.4	18.6	0.1790
23.4	0.948	2.0	11.5	0.466	51.4	10.8	0.1040
37.2	1.507	0.5	12.0	0.486	53.6	7.5	0.0721
51.4	2.08	0.2	12.2	0.494	54.5	6.1	0.0587
65.1	2.64	0.1	12.3	0.498	54.9	5.6	0.0539
79.4	3.21	0.1	12.4	0.503	55.4	5.3	0.0510
93.1	3.77	0.1	12.5	0.506	55.8	5.0	0.0481
107.3	4.35	0.1	12.6	0.510	56.3	4.7	0.0452

TABLE C-57

Displacement Test Recovery Data - Test Number 56

Pore Volume: 26.5 cc Temperature: 80° F Oil: Lloydminster 'Crude
Injected Phase: 0.005% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 3 Porosity: 46.1% Brine Permeability: 4.37 Darcies
Initial Water Saturation: 15.1% Initial Oil In Place: 22.5 cc
Sand Density: 2.68 gm/cc $\underline{U}_O = 940$ cp $\underline{U}_W = 0.993$ cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W_i	W_i	ΔN_p	N_p			ΔP	$\Delta P / \Delta P_i$
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	172.7	1.0
1.5	0.057	1.2	1.2	0.045	5.3	78.2	0.453
5.1	0.193	1.6	2.8	0.106	12.4	52.0	0.301
15.5	0.585	2.9	5.7	0.215	25.3	23.3	0.1350
26.6	1.004	2.3	8.0	0.302	35.6	17.0	0.0985
40.7	1.536	2.4	10.4	0.393	46.3	13.3	0.0770
55.9	2.11	1.9	12.3	0.465	54.7	10.7	0.0620
70.0	2.64	1.6	13.9	0.525	61.8	9.3	0.0538
83.9	3.16	1.4	15.3	0.578	68.0	8.5	0.0492
97.6	3.68	1.2	16.5	0.623	73.4	7.7	0.0446
111.2	4.20	1.1	17.6	0.664	78.3	7.1	0.0411

TABLE C-58

Displacement Test Recovery Data - Test Number 57

Pore Volume: 24.2 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 0.005% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 41.4% Brine Permeability: 9.01 Darcies
Initial Water Saturation: 12.0% Initial Oil In Place: 21.3 cc
Sand Density: 2.66 gm/cc U_O = 940 cp U_w = 0.993 cp

<u>Fluid Injected.</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	72.3	1.0
2.6	0.108	2.6	2.6	0.108	12.2	33.5	0.468
5.6	0.231	1.4	4.0	0.165	18.8	20.7	0.286
14.7	0.608	1.4	5.4	0.223	25.4	8.3	0.1148
24.9	1.029	0.7	6.1	0.252	28.6	5.3	0.0733
38.6	1.595	0.7	6.8	0.281	31.9	4.0	0.0553
52.5	2.17	0.5	7.3	0.302	34.3	3.3	0.0456
69.0	2.85	0.4	7.7	0.318	36.2	2.6	0.0360
83.3	3.44	0.2	7.9	0.326	37.1	2.1	0.0290
98.2	4.06	0.1	8.0	0.331	37.6	1.8	0.0249
112.0	4.63	0.0	8.0	0.331	37.6	1.5	0.0208

TABLE C-59

Displacement Test Recovery Data - Test Number 58

Pore Volume: 24.1 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 0.005% NaOH in Brine Displacement Rate: 40 cc/hr
Sand No: 2 Porosity: 41.2% Brine Permeability: 6.00 Darcies
Initial Water Saturation: 10.0% Initial Oil In Place: 21.7 cc
Sand Density: 2.66 gm/cc $\underline{U}_O = 940$ cp $\underline{U}_W = 0.993$ cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W_i	W_i	ΔN_p	N_p			ΔP	$\Delta P / \Delta P_i$
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	102.9	1.0
2.7	0.112	2.6	2.6	0.108	12.0	45.0	0.437
5.3	0.220	0.9	3.5	0.145	16.1	27.7	0.269
14.9	0.619	1.8	5.3	0.220	24.4	10.0	0.0972
23.9	0.992	0.8	6.1	0.253	28.1	6.1	0.0592
38.1	1.580	1.0	7.1	0.295	32.7	4.2	0.0408
52.6	2.18	0.7	7.8	0.324	36.0	3.5	0.0340
66.4	2.75	0.6	8.4	0.349	38.7	3.1	0.0301
80.1	3.32	0.4	8.8	0.365	40.6	2.7	0.0262
93.7	3.89	0.3	9.1	0.378	42.0	2.5	0.0243
107.6	4.46	0.4	9.5	0.394	43.8	2.4	0.0233

TABLE C-60Displacement Test Recovery Data - Test Number 59

Pore Volume: 26.8 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% Na₃PO₄ in Brine Displacement Rate: 40 cc/hr
Sand No: 3 Porosity: 46.6% Brine Permeability: 5.42 Darcies
Initial Water Saturation: 15.3% Initial Oil In Place: 22.7 cc
Sand Density: 2.67 gm/cc U_O = 940 cp U_w = 0.933 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
<u>W_i</u>	<u>W_i</u>	<u>ΔN_p</u>	<u>N_p</u>			<u>ΔP</u>	<u>ΔP/ΔP_i</u>
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	140.1	1.0
3.0	0.112	3.0	3.0	0.112	13.2	105.6	0.754
7.7	0.287	4.1	7.1	0.265	31.3	90.0	0.642
18.3	0.583	4.8	11.9	0.444	52.4	23.6	0.1684
29.3	1.093	0.4	12.3	0.459	54.2	12.8	0.0914
43.0	1.604	0.1	12.4	0.463	54.6	9.8	0.0700
57.5	2.14	0.0	12.4	0.463	54.6	7.7	0.0550
72.6	2.71	0.0	12.4	0.463	54.6	6.6	0.0471
86.4	3.22	0.0	12.4	0.463	54.6	5.9	0.0471
100.3	3.75	0.0	12.4	0.463	54.6	5.2	0.0371

TABLE C-61

Displacement Test Recovery Data - Test Number 60

Pore Volume: 24.9 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% Na₃PO₄ in Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 42.6% Brine Permeability: 9.25 Darcies
Initial Water Saturation: 12.0% Initial Oil In Place: 21.9 cc
Sand Density: 2.68 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	58.1	1.0
3.2	0.129	3.2	3.2	0.129	14.6	39.5	0.680
7.0	0.281	3.5	6.7	0.269	30.6	21.5	0.370
18.2	0.731	5.6	12.3	0.494	56.2	7.5	0.129
29.7	1.193	1.2	13.5	0.542	61.6	2.5	0.0430
43.5	1.748	0.1	13.6	0.546	62.1	1.2	0.0206
56.9	2.29	0.0	17.6	0.546	62.1	1.1	0.01883
70.5	2.83	0.0	13.6	0.546	62.1	0.9	0.01550
84.0	3.38	0.1	13.7	0.550	62.6	1.0	0.01721
97.5	3.92	0.0	13.7	0.550	62.6	0.8	0.01377
111.2	4.47	0.0	13.7	0.550	62.6	0.9	0.01550

TABLE C-62

Displacement Test Recovery Data - Test Number 61

Pore Volume: 24.6 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% Na₃PO₄ in Brine Displacement Rate: 40 cc/hr
Sand No: 2 Porosity: 42.1% Brine Permeability: 6.73 Darcies
Initial Water Saturation: 9.3% Initial Oil In Place: 22.3 cc
Sand Density: 2.68 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	88.0	1.0
3.1	0.126	3.1	3.1	0.126	13.9	57.0	0.648
6.9	0.280	3.7	6.8	0.376	30.5	27.0	0.307
16.7	0.679	2.4	9.2	0.374	41.3	16.1	0.183
25.6	1.041	0.6	9.8	0.398	44.0	15.6	0.1772
41.5	1.687	0.7	10.5	0.427	47.1	6.4	0.0727
55.2	2.24	0.0	10.5	0.427	47.1	5.1	0.0580
68.8	2.80	0.0	10.5	0.427	47.1	4.3	0.0449
82.5	3.35	0.0	10.5	0.427	47.1	3.8	0.0432
97.0	3.94	0.0	10.5	0.427	47.1	3.5	0.0398

TABLE C-63

Displacement Test Recovery Data - Test Number 62

Pore Volume: 23.8 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% (NaPO₃)₆ in Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 40.7% Brine Permeability: 9.87 Darcies
Initial Water Saturation: 11.4% Initial Oil In Place: 21.1 cc
Sand Density: 2.66 gm/cc U_O = 940 cp U_W = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	60.9	1.0
2.6	0.109	2.6	2.6	0.109	12.3	32.3	0.530
5.0	0.210	1.1	3.7	0.155	17.5	17.0	0.279
11.0	0.462	1.1	4.8	0.202	22.8	8.8	0.1445
17.5	0.735	0.6	5.4	0.227	25.6	6.1	0.1002
26.2	1.101	0.5	5.9	0.248	28.0	4.6	0.0755
36.7	1.542	0.4	6.3	0.265	29.8	3.8	0.0624
50.7	2.13	0.3	6.6	0.277	31.3	3.3	0.0542
65.3	2.74	0.3	6.9	0.290	33.7	3.0	0.0493
80.2	3.37	0.2	7.1	0.298	33.6	2.6	0.0427
96.7	4.06	0.2	7.3	0.306	34.6	2.3	0.0378
110.2	4.64	0.1	7.4	0.311	35.1	2.2	0.0361
124.7	5.24	0.1	7.5	0.315	35.5	2.2	0.0361

TABLE C-64

Displacement Test Recovery Data - Test Number 63

Pore Volume: 23.8 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% Na₂CO₃ in Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 40.7% Brine Permeability: 9.08 Darcies
Initial Water Saturation: 10.5% Initial Oil In Place: 21.3 cc
Sand Density: 2.67 gm/cc U_O = 940 cp U_w = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
W _i	W _i	ΔN _p	N _p			ΔP	ΔP/ΔP _i
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	60.6	1.0
3.6	0.151	3.6	3.6	0.151	16.9	43.3	0.715
7.0	0.294	2.9	6.5	0.273	30.5	27.7	0.457
15.4	0.647	4.2	10.7	0.450	50.2	10.1	0.1667
25.2	1.059	1.3	12.0	0.505	56.2	5.5	0.0908
39.3	1.651	0.7	12.7	0.534	59.6	2.1	0.0347
52.2	2.20	0.2	12.9	0.542	60.6	2.5	0.0412
66.8	2.81	0.2	13.1	0.551	61.5	2.0	0.0330
80.6	3.39	0.1	13.2	0.555	62.0	1.3	0.0214
94.6	3.98	0.1	13.3	0.559	62.5	1.3	0.0214
108.2	4.55	0.1	13.4	0.563	62.9	1.3	0.0214
121.9	5.12	0.0	13.4	0.563	62.9	1.2	0.0198

TABLE C-65

Displacement Test Recovery Data - Test Number 64

Pore Volume: 23.8 cc Temperature: 80° F Oil: Lloydminster Crude
Injected Phase: 1% Na₄P₂O₇ in Brine Displacement Rate: 40 cc/hr
Sand No: 1 Porosity: 40.7% Brine Permeability: 8.39 Darcies
Initial Water Saturation: 10.0% Initial Oil In Place: 21.2 cc
Sand Density: 2.67 gm/cc U_O = 940 cp U_w = 0.993 cp

<u>Fluid Injected</u>		<u>Recovery</u>		<u>Cumulative Oil Recovery Fraction</u>		<u>Pressure Drop</u>	
<u>W_i</u>	<u>W_i</u>	<u>ΔN_p</u>	<u>N_p</u>			<u>ΔP</u>	<u>ΔP/ΔP_i</u>
cc	PV	cc	cc	PV	% IOIP	psi	psi/psi
0.0	0.0	0.0	0.0	0.0	0.0	69.0	1.0
2.6	0.109	2.6	2.6	0.109	12.3	37.5	0.543
5.3	0.223	1.4	4.0	0.168	18.9	17.5	0.254
11.8	0.496	1.1	5.1	0.214	24.1	6.5	0.0941
18.4	0.773	1.2	6.3	0.265	29.7	4.9	0.0710
30.2	1.269	2.1	8.4	0.353	39.6	4.2	0.0609
49.6	2.08	3.7	12.1	0.509	57.1	3.8	0.0551
66.3	2.78	3.0	15.1	0.635	71.3	3.2	0.0462
81.9	3.44	2.3	17.4	0.731	82.2	2.7	0.0391
96.2	4.04	1.4	18.8	0.790	88.7	2.8	0.0406
109.3	4.60	1.0	19.8	0.832	93.5	2.9	0.0420
122.5	5.15	1.8	20.6	0.866	97.3	3.5	0.0507

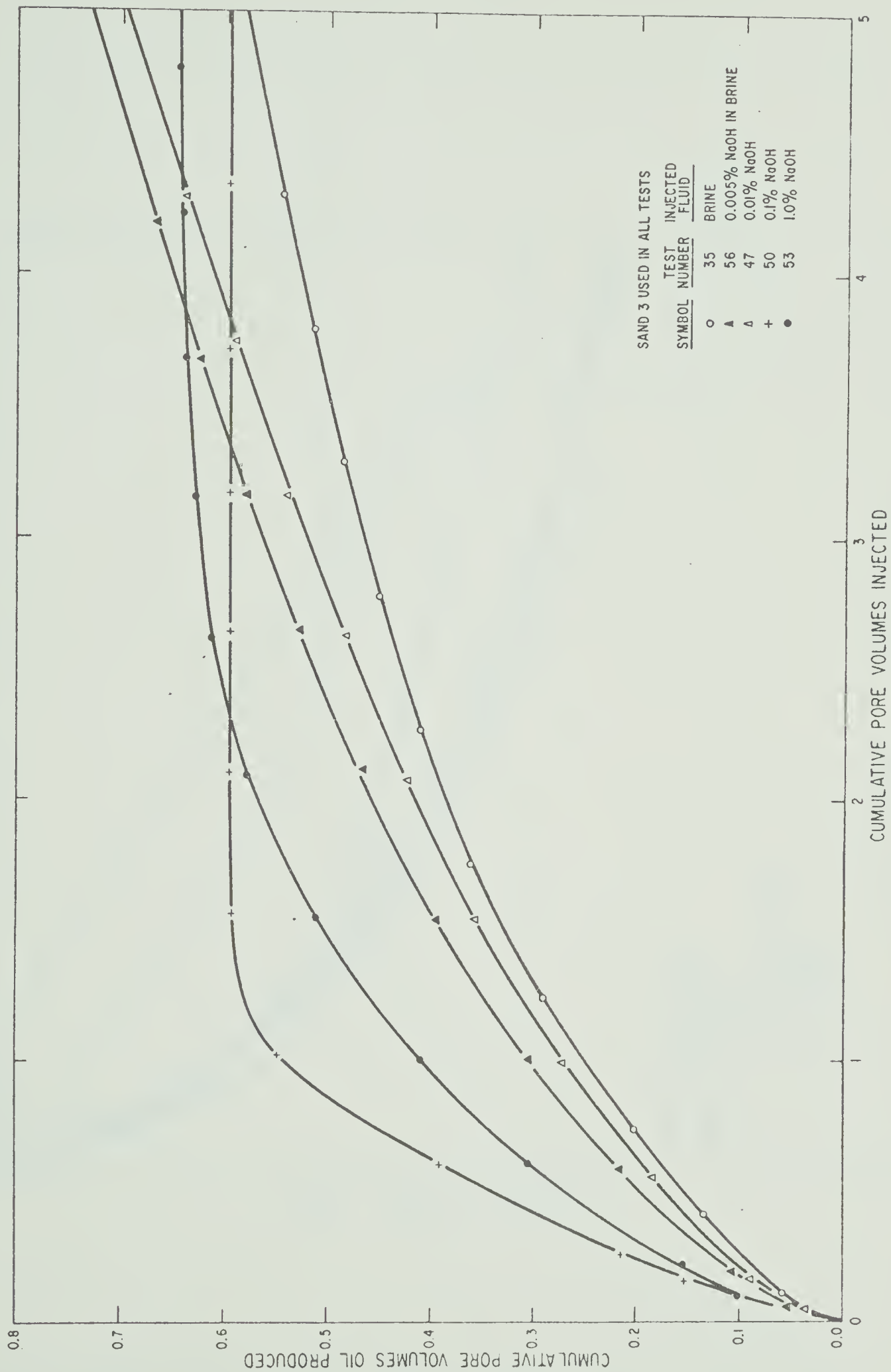


FIG. C-1 - EFFECT ON OIL RECOVERY DUE TO SODIUM HYDROXIDE IN BRINE SOLUTION DISPLACEMENT TESTS — SAND 3

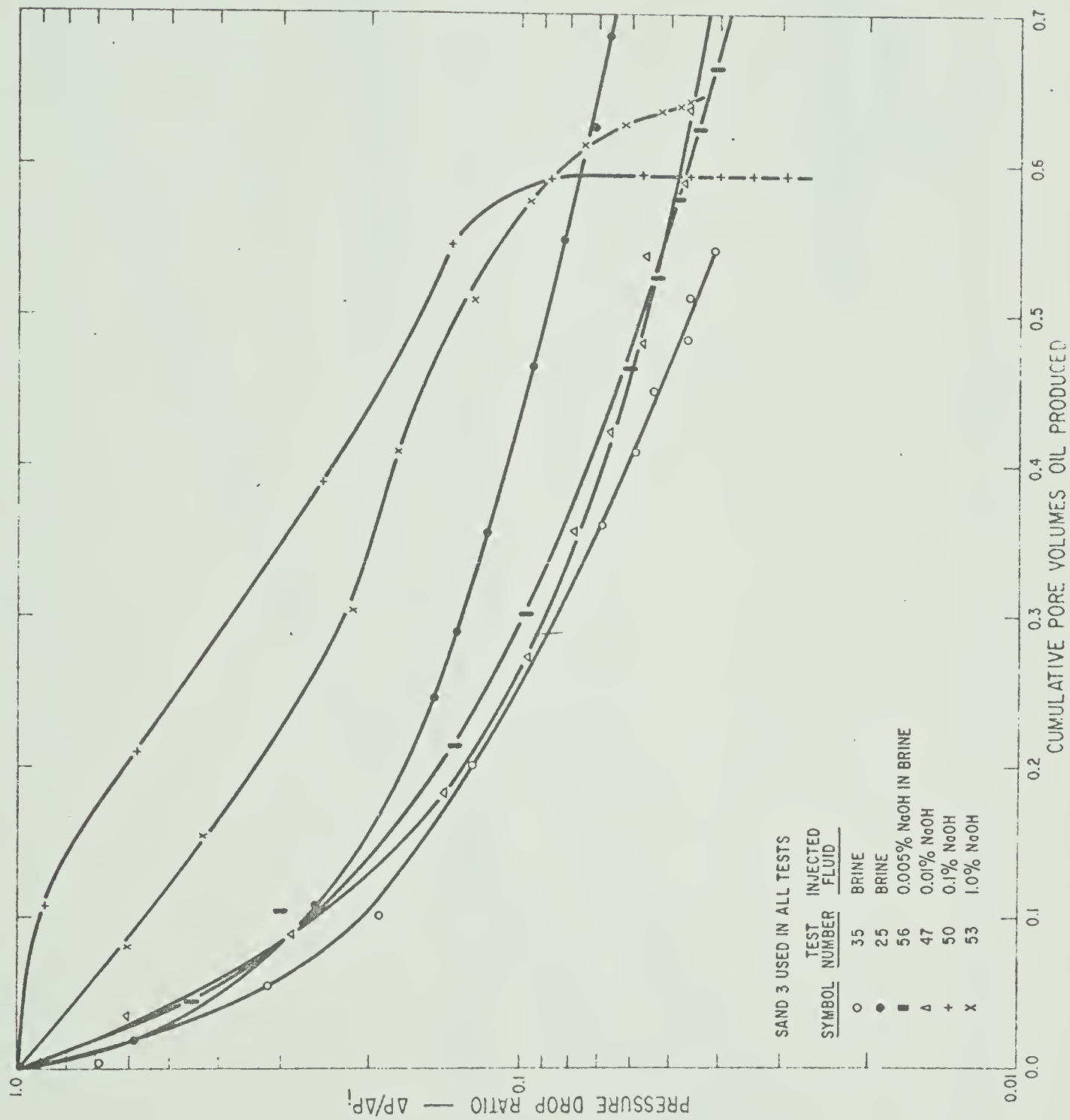


FIG. C-2-PRESSURE BEHAVIOUR FOR SODIUM HYDROXIDE IN BRINE SOLUTION DISPLACEMENT TESTS — SAND 3

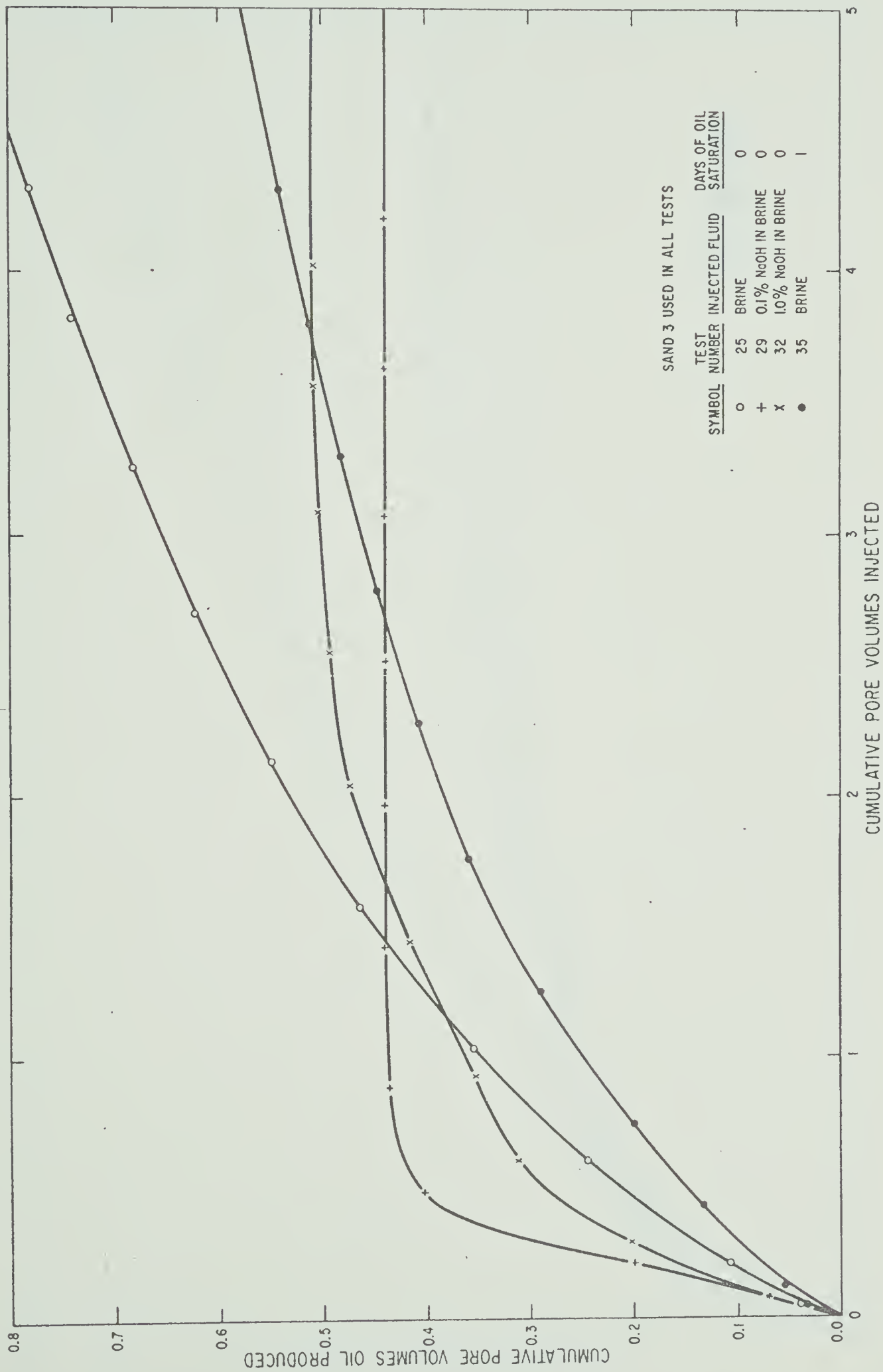


FIG.C-3 - INFLUENCE OF TIME OF OIL SATURATION AND SODIUM HYDROXIDE ON OIL RECOVERY BY DISPLACEMENT TESTS



FIG. C-4 - COMPARISON OF OIL RECOVERY FOR 0.005 PERCENT SODIUM HYDROXIDE
IN BRINE SOLUTION DISPLACEMENT TESTS



FIG.C-5 - COMPARISON OF OIL RECOVERY FOR 0.01 PERCENT SODIUM HYDROXIDE
IN BRINE SOLUTION DISPLACEMENT TESTS

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